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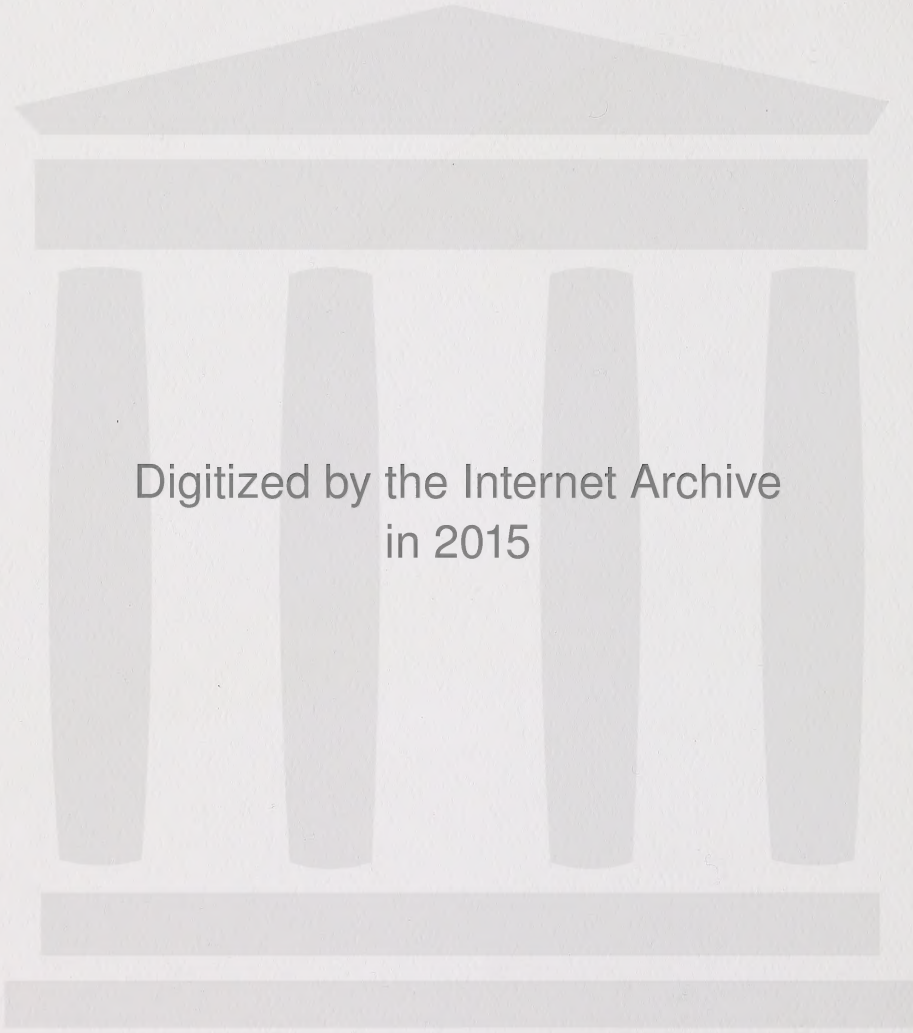
Pressure and Deliverability Testing Oil and Gas Wells

Minimum Requirements and Recommended Practices

Alberta Energy and Utilities Board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Pressure and Deliverability Testing Oil and Gas Wells

Minimum Requirements and Recommended Practices

May 1999

ALBERTA ENERGY AND UTILITIES BOARD
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1 Introduction

Well test information is second only to production data in importance for the prudent management of oil or gas reservoirs. As such, well testing is an integral part of the overall production and depletion strategy of a reservoir. The lowest costs and the most benefit are realized when an adequate number of high quality tests are run throughout the producing life of the reservoir.

The requirements detailed in this Guide are EUB regulations, as enacted under sections 7, 11, and 15 of the Oil and Gas Conservation Regulations. This Guide addresses bottom-hole pressure and deliverability tests, flaring issues, drill stem tests, gas and fluid sampling, and analysis. The well testing requirements defined in this Guide are minimum requirements and the EUB may request testing that exceeds these requirements, where a need has been identified. Any relief from testing, or special testing requirements, which predate this Guide, will remain in effect. In general, complying with this Guide should not result in more frequent testing for existing wells or pools, and may result in reduced testing. On the other hand, test methods should be upgraded, if necessary, to meet or exceed those standards specified in this Guide.

Alberta's regulations for testing oil and gas wells were introduced in the 1960's, and have been revised a number of times. While these regulations have served reasonably well, both the operational scenario and the technology of well testing have changed significantly in the last decade. These changes brought into focus the need for revised requirements and a new regulatory environment, whereby the requirements can be revisited and modified as conditions warrant.

In early 1987, the Well Testing Special Interest Group was formed through The Petroleum Society of The Canadian Institute of Mining, Metallurgy, and Petroleum. The need for a review of well testing regulations was immediately recognized, and an Industry-EUB technical committee was formed. The Committee's main objectives were to:

- improve the quality of well test data,
- reduce data gathering costs wherever possible, and
- clarify well test regulations.

The first edition of Guide 40, issued as a draft on 1 April 1990, was developed by the Committee to address these objectives. It became the framework for a new regulatory environment, where the licensee/operator gained more flexibility in testing, and assumed greater responsibility for test quantity and quality.

In the mid-1990's, the changing economic environment in Alberta resulted in widespread restructuring and down sizing. Government funding cutbacks necessitated a re-evaluation of EUB processes, and feedback was solicited from industry. The results of this re-evaluation indicated the importance of fair and equitable enforcement of EUB regulations and requirements, and a greater shift of responsibility to the licensee/operator for ensuring regulatory compliance.

A second Industry-EUB technical committee was formed in June 1996, to review the minimum requirements and compliance strategies for well testing. The result was the further reduction of minimum survey requirements and the implementation of non-compliance measures, as detailed in the June 1997 version of Guide 40. This Committee functions as a standing committee to provide recommendations to the EUB on well testing matters.

In November of 1998, this Committee was reassembled to review the requirements, and the effects of the non-compliance measures implemented in 1997, to determine what works, what needs improvement, and identify any new concerns that may be pertinent to well testing.

The Committee has also considered the impact of flaring and venting on our environment, and the recommendations made to the EUB by the Clean Air Strategic Alliance (CASA). The EUB has accepted the framework recommended by CASA to reduce provincial solution gas flare emissions which will be detailed in the forthcoming EUB Guide "*Upstream Petroleum Industry Flaring Guide*". The new flaring guide will also address flare performance requirements, and new requirements and information regarding research and technology in this direction. Changes will be ongoing in this area over the next few years as research continues with the Petroleum Technology Alliance of Canada, several Federal and Provincial departments, and the participation of industry operators and technology suppliers.

This edition of Guide 40 incorporates the findings of the joint EUB - Industry Well Test Committee, on flaring in conjunction with well testing, and requirements for electronic data reporting. Input has been solicited from technical experts, various industry groups, and the EUB. It is intended to serve as a handbook for testing oil and gas wells. The requirements it contains should pass most reviews of cost and reasonableness. Test quality will improve if licensees/operators use properly trained personnel, and take care in designing, conducting, analyzing, and reporting their tests. The contents of this Guide should be useful to anyone involved in testing oil and gas wells, regardless of their level of experience.

To assist licensees/operators in complying with well test requirements, the EUB offers the following services:

- For easier access and better service in well test matters, try our new Well Test Helpline at welltest-helpline@eub.gov.ab.ca
- All information pertaining to electronic data submission, including Guide 52, templates for reporting formats, examples, frequently asked questions, are available from the EUB website at www.eub.gov.ab.ca/bbs/dds/welltest/welltest.htm
- Annual survey schedules for oil and gas pools, complete with current status of completion, are available from the EUB website at www.eub.gov.ab.ca/bbs/data/welltestreq.htm. These files are updated biweekly.
- A file listing the wells with outstanding initial pressure and deliverability requirements are also available from the EUB website at www.eub.gov.ab.ca/bbs/data/welltestreq.htm. These files are updated biweekly.

More details on these services are available throughout this Guide. Appendix C has a complete listing of EUB website and e-mail addresses pertinent to well testing.

1.1 Changes to Guide 40

The format of this Guide has been changed to provide easier access to specific subject matter. All information on a particular subject will now be found in one place, whether defining a requirement, recommended practice, or example. Some key revisions to this third edition are:

- The majority of the regulations have been moved from section 2 to Appendix B.
- More comprehensive information on deliverability testing has been added to section 4.
- Information is included on flaring as it pertains to well testing.
- More comprehensive information has been added on development of survey schedules and qualifying for relaxation.
- Information from section 7 addressing modifications to annual survey requirements has been moved up to section 4.6 – Annual Survey Requirements.
- The EUB Well Test Section is now responsible for all aspects of drill stem tests (DSTs), and has included more information on submission of DSTs, and related compliance issues.
- Gas and Fluid analysis is now under the jurisdiction of the EUB Well Test Section as well, and has also been included in this Guide.
- Information on electronic reporting requirements for well testing is included.
- We have added more information on EUB processes dealing with compliance issues, licensee responsibilities, and details for appealing non-compliance consequences.
- A list of contacts, telephone numbers, e-mail addresses, and website URLs dealing with well test matters has been added as Appendix C.

2 Regulations Pertinent to Well Testing

The following are regulations from the Oil and Gas Conservation Regulations. Section 11.102 provides the authority to set requirements for well testing within this Guide. Section 11.120 is the requirement for all tests to be submitted. Appendix B is a complete listing of all the regulations pertinent to gathering well test data, gas and fluid analysis, drill stem tests, and flaring in conjunction with well testing. More information on flaring/emissions is available in Interim Directive (ID 91-2) and the new EUB "*Upstream Petroleum Industry Flaring Guide*" will address changes to the flaring regulations as they pertain to well testing.

11.102 (1) The licensee of a well or the representative of the licensee shall conduct and report to the Board tests for all gas and oil wells in accordance with the current edition of Guide 40, "Pressure and Deliverability Testing Oil and Gas Wells – Minimum Requirements and Recommended Practices", published by the Board.

(2) Notwithstanding subsection (1), the Board may, upon application by the licensee of a well or the representative of the licensee, grant relief from any or all of the requirements in the Guide.

11.120 (1) The licensee of a well shall supply to the Board without delay the data and results of:

(a) each bottomhole sample analysis or other pressure-volume-temperature analysis, in duplicate

(b) each measurement or test made on the well for the purpose of obtaining information pertaining to a formation in which the well is completed, including volumes of oil, gas, condensate or water produced, flowing
or
static pressure measurements, pressure build-up, fall-off and drawdown tests, reservoir limits tests, interference tests, and two-rate tests,

(c) where the well is primarily productive of gas, one copy of each deliverability test including field notes, flow rate calculations, summary sheet (Form EG-32) and any supplementary data and calculations related to a proper interpretation of the test, and *(this regulation is currently being updated)*

Excerpt from Appendix 4 - EUB Guide 7 – Production Accounting Handbook

You must file an S-1 statement for a well that has produced any fluid (crude oil, crude bitumen, condensate gas, or water) for any reason, reporting the volumes produced. (This is interpreted by the EUB to include cleanup and test volumes, whether flared, vented, or in-line). These volumes and the method of production (flared, vented, or in-line) must also be reported in the AOF.PAS electronic report.

When an S-1 statement is filed, an S-2 statement must also be filed. An S-4 statement is not required for test production, but must be submitted when placing the well on production".

3 Summary of Basic Minimum Requirements for Well Testing as of May 1999

This section contains the condensed version of the basic minimum requirements for testing oil and gas wells and references the appropriate section for further clarification and explanation. The EUB may request surveys that exceed these minimum requirements, should they be deemed necessary.

The well licensee or its representative shall comply with the minimum requirements defined below, regarding the conducting and reporting of tests for its gas and oil wells. Any failure to comply with these minimum requirements will result in the consequences defined in section 6 of this Guide. For annual pressure requirements, the licensee indicated on the EUB website as the coordinating operator will be liable for compliance with the annual requirements for that pool. For initial pressure and deliverability requirements, submission of drill stem tests, and gas and fluid analysis, the licensee responsibility will also be indicated on the EUB website. Please notify the Well Test Section immediately of any changes in responsibility for fulfilling the well test requirements.

3.1 Test Quality Standards

(See section 5 of this Guide for additional information.)

All tests submitted to fulfil survey requirements must:

- **meet the "Acceptable Survey Standards", as defined in section 5, and**
- **be reported in the appropriate electronic format defined in Guide 52.**

More information on electronic reporting is available on the EUB's website at:

www.eub.gov.ab.ca/bbs/dds/welltest/welltest.htm

The "Acceptable Survey Standards" for required tests have been translated into edits which are defined in EUB Guide 52, *Electronic Capture of Well Test Data*. Some edits are critical, which will result in the file being rejected. Other edits have been identified as non-critical and will not cause the file to be rejected. The non-critical edits are a bit more subjective, and require some interpretation. They will be administered by an audit process. Tests not meant to fulfil any requirement should be clearly indicated in the Test Data Section of the appropriate PAS file. Setting the [PRPS] (purpose flag) to "N"(o), will turn-off the "acceptable survey" edits.

3.2 Initial Pressure Testing Requirements

(See section 4.2 of this Guide for additional information.)

Initial subsurface pressures are required on productive oil and gas wells as follows

- **Gas Wells – on all productive wells, within the first three months of production (one well per section),**

- **Oil Wells – on all productive exploratory, discovery, or step-out wells; prior to any sales or production, other than test production (one well per quarter section).**

Initial pressures are not required on step-out wells to existing oil pools if **all** of the following conditions are met:

- the well is drilled where step-out does not exceed one legal subdivision, **and**
- the pool already consists of a minimum of four wells, **and**
- all survey requirements have been fulfilled, **and**
- there is no other pool in the same formation, in an adjacent quarter section, **and**
- the licensee/operator can provide evidence, upon request, indicating the well is completed in the existing pool.

Any further development in the quarter section, outside of the one LSD buffer zone, requires an initial pressure survey (one well per quarter section).

Other testing methods that may be acceptable are addressed in section 5.

3.3 Deliverability Testing Requirements

(See section 4.3 of this guide for additional information.)

Bottomhole deliverability relationships are required for all producing gas wells prior to or during the first three consecutive calendar months of sales.

3.3.1 Flaring in Conjunction with Testing

(See section 4.4 of this guide for additional information.)

Any flaring or venting in conjunction with well testing, must be conducted in accordance with sections 7.055, 11.135, and 15.240 of the Oil and Gas Conservation Regulations, IL 91-2, and the new "*Upstream Petroleum Industry Flaring Guide*".

- The flaring of any gas where the hydrogen sulfide content equals or exceeds 50 moles per kilomole requires a written approval from the

EUB Environment, Safety &Technical Services Group as per sections 7.055 and 15.240 of the Oil and Gas Conservation Regulations.

- The flaring of any gas where the hydrogen sulfide content is less than 50 moles per kilomole must be conducted in accordance with IL 91-2

- Approval is required from the EUB Systems and Resource Information Group if the total volume flared is expected to exceed 600 e^3m^3 (and the hydrogen sulphide content is less than 50 moles per kilomole) as per section 11.135 of the Oil and Gas Conservation Regulations.

- All flaring must be conducted in accordance with the regulations as detailed in Appendix B of this Guide, and the forthcoming *"Upstream Petroleum Industry Flaring Guide"*.

- All production for whatever purpose, whether flared, vented, or in-line; must be reported on EUB S-1 Monthly Production Statements, and S-2 Monthly Disposition Statements, as well as AOF.PAS electronic reporting formats.

3.4 Drill Stem Tests

(See section 4.7 of this guide for further information.)

There are no regulations governing the conducting of DSTs, only for submission of DSTs.

- **All DSTs conducted, including misruns, must be submitted to the EUB in DST.PAS electronic format, within 30 days of the well's finished drilling date.**

3.5 Gas and Fluid Analysis

(See section 4.8 of this guide for further information.)

All gas and fluid analysis conducted on samples gathered at a well, which are representative of the formation (not mixed stream), must be submitted.

Further, gas and/or fluid analyses are required in conjunction with the following tests:

- DSTs conducted on wells outside of existing pools, as per the current EUB G-Order
  - fluid analysis is required if fluid is recovered during the test
  - gas analysis is required if gas to surface during the test

- All deliverability tests require gas analysis for the fluid analysis correlation and must therefore be submitted with an AOF test on all wells drilled outside of existing pools, as per the current EUB G-Order.

- Initial Pressure Tests conducted on wells outside of existing pools, as per the current EUB G-Order:

  - gas analysis is required for oil and gas wells,
  - fluid analysis is required for oil wells, and gas wells producing liquids, OR provide details regarding the source of analysis used in the correlation.

- Acoustic Well Sounder Tests require analysis information when calculating acoustic pressures:

  - gas analysis is required for all acoustic tests,
  - fluid analysis is required when fluids are present in the wellbore, OR
  - provide details regarding the source of analysis used in the correlation.

- Pressure Transient Analysis requires gas and fluid properties for calculations, OR, provide details regarding the source of analysis used in the correlation.

3.6 Annual Pressure Survey Requirements

(See section 4.5 of this guide for additional information.)

Annual pressure surveys must be conducted by year end (December 31) for oil and gas pools, as specified in the annual survey schedules:

- Survey 25 per cent of the producing well count in OIL POOLS, based on quarter section spacing (e.g., approximately one survey per productive section).

- Survey 25 per cent of the producing well count in GAS POOLS, based on one section spacing.

Section 4.6.8 includes details regarding survey requirements for pools with reduced spacing.

3.6.1 Licensee/Operator Requirements

(See section 4.5.5 of this Guide for additional information.)

Where more than one licensee/operator produces from the same pool:

- **A Coordinating Operator will be designated by the EUB and deemed responsible for coordinating the surveys for the pool(s).**

- **All licensees/operators in the pool(s) are required to cooperate with the Coordinating Operator.**

See section 6 on compliance and enforcement.

3.7 Submission Requirements

(See section 4.9 of this guide for further information.)

The results of all well tests conducted must be submitted to the EUB, in electronic format, as per section 11.120 of the Oil and Gas Conservation Regulations, and Guide 52.

- **All pressure and deliverability tests must be submitted within 90 days of completing the field work, including reporting of volumes and methods produced during cleanup and testing.**

- **All DSTs must be submitted within 30 days of the well's finished drilling date, including misruns.**

- **All gas and fluid analysis must be submitted within 45 days of the completion of the test.**

- **All volumes produced, whether flared, vented or in-line must also be reported on EUB S-1 and S-2 forms as per section 4.9 of this Guide. See EUB Guide 7 – Production Accounting Handbook for further information.**

Notwithstanding the above, a test that failed and provides no useful data, especially where the use of this information might be misleading, does not have to be submitted. This does not include Drill Stem Tests, as detailed above.

Although there are no basic requirements for wells in designated oil sands areas, all tests conducted must still be submitted to the EUB. With the concerns regarding the possible effects of gas production on underlying bitumen reserves, pressure information has become more critical than ever in these areas, including the gas wells overlying the bitumen deposits.

4 Clarification of the Minimum Requirements

Sections 4 through 7 of this Guide provide additional interpretation of the basic testing requirements, guidelines for meeting and/or modifying the basic requirements, and examples of situations where the EUB may require special testing which exceed these minimums. Together they represent the minimum requirements for well testing which are considered essential for prudent reservoir management. Recommended practices are also included under many of the sections, to assist well testers in meeting their requirements and obtaining the best data possible.

4.1 Basic Requirements

The basic requirements apply to pools and new wells drilled, until or unless the licensee/operator and the EUB agree relief is appropriate. The requirements focus on data gathering from discovery until a pool is fully developed. Gathering quality data during this phase is critical. The basic requirements, with modifications for relief when appropriate, should address the testing needs of the majority of Alberta's reservoirs.

Non-compliance with these well testing requirements will result in enforcement actions as developed by the joint Industry-EUB Committee, to be consistent with the EUB's Corporate Compliance Enforcement Policy. Details are described in section 6 of this Guide. All enforcement actions for non-compliance shall be timely, effective, and appropriate to the severity of the issue. Repeated or continued non-compliance shall be dealt with through escalating enforcement consequences.

4.2 Initial Pressure Testing

Requirement:

Initial subsurface pressure tests are required on new productive oil and gas wells and report in electronic format (PAS) as follows:

- **Gas Wells – on all new wells drilled, within the first three months of production (one well per section),**
- **Oil Wells – on all exploratory, discovery, or step-out wells; prior to any sales or production, other than test production (one well per quarter section)**

An accurate initial pressure is probably the most important pressure taken in a well. It determines the initial pool pressure in exploratory wells, it helps delineate pools in development wells, and it can show the drainage and recovery efficiency in infill wells. Without this pressure, subsequent pressures may be of limited value.

The EUB has added a list of those wells with outstanding initial requirements on our website, at www.eub.gov.ab.ca/bbs/data/welltestreq.htm. This list will be updated biweekly, and will display the unique well identifier, the licensee, and the type of test required.

4.2.1 Relaxation of Initial Pressure Requirements on Step-out Oil Wells

Initial pressures are not required on step-out wells to existing oil pools if **all** of the following conditions are met:

- the well is drilled where step-out does not exceed one legal subdivision, **and**
- the pool already consists of a minimum of four wells, **and**
- all survey requirements have been fulfilled, **and**
- there is not another pool in the same formation, in an adjacent quarter section, **and**
- the licensee/operator can provide evidence upon request, indicating the well is completed in the existing pool.

Important Note: **If you do not survey a step-out well any further development drilling in that quarter section requires testing, even if that quarter section gets added to the EUB G-Order, (one initial survey must be conducted per quarter section).**

The initial survey requirement can be waived for wells drilled outside of an existing pool boundary (using the EUB's current G-Order ***at time of drilling***, as per Figure 1 on the following page), where the step-out is within the one legal subdivision (LSD) buffer zone and there is a high probability of extending the existing pool. The conditions listed above permit the waiver of the initial pressure survey requirement, while ensuring that only pools with an established pressure history and areal extent receive waiver. Also, they ensure that wells between two same formation pools have adequate initial pressure data to allow determination of pools.

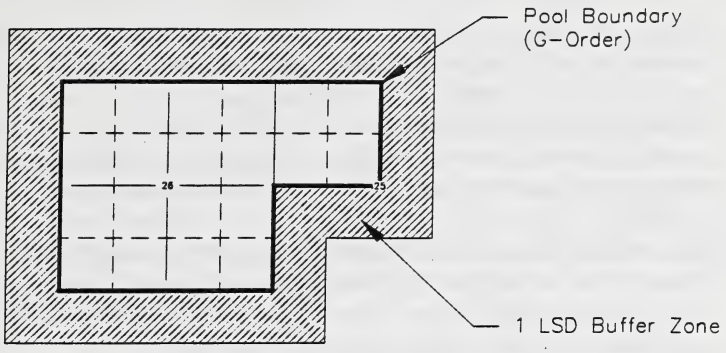

Figure 1 G-Order with Buffer Zone

The EUB does not currently have an automated process to administer the waiver for these step-out wells. Therefore, it is necessary for the licensee to respond to the notice letter, and advise EUB staff that the well qualifies for exemption due to the step-out rule. EUB staff will then review the situation and determine the requirement accordingly

Similar problems are often experienced with wells drilled within a pool EUB G-Order that do not initially get coded into the pool, or into the South Eastern Alberta Shallow Gas System. In these cases, the licensee is also required to respond to any notice letters, and advise EUB staff of the criteria for exemption.

4.2.2 Initial Pressures on Gas Wells

Initial pressures have always been required on all new productive gas wells. The initial pressure is considered to be more important to the management of the resources, than the deliverability test. With the automation of well test submission and the subsequent changes made to our database, the EUB will now administer the initial pressure requirements for gas wells. Effective 1 June 1999 the initial pressure requirement for gas wells will be administered in the same manner as oil wells, with the same compliance processes to apply.

4.2.3 Recommended Practices for Initial Pressure Tests

The initial stabilized pressure should be taken before any significant production or depletion of the reservoir occurs. Taking the initial pressure after a reasonable cleanup flow period is acceptable providing the test shows that a stabilized reservoir pressure has been reached. But it would be unacceptable, for example, to wait until the end of the 4-month New Oil Well Production Period to take an oil wells' initial pressure, or to apply for relief from testing.

When using a static gradient for an initial pressure test, the licensee/operator needs to be aware that the formation has been disturbed and some drawdown has occurred during drilling, completion, and clean up. A static gradient without sufficient shut-in may not indicate a stabilized pressure. In many instances, running a static gradient and leaving the gauges on bottom for a few hours gives a good indication of stability for an initial pressure.

Although the taking of an initial pressure is not required for infill oil wells, it is recommended whenever practical to do so. It should also be noted that initial pressures can be used to meet the annual pool pressure survey requirement providing areal coverage is satisfactory.

Under certain conditions, an acceptable initial pressure can be obtained from alternative methods as addressed in section 5 of this guide.

4.3 Gas Well Deliverability Testing

Requirement:

Obtain a sandface deliverability relationship for ALL producing gas wells from either a single or multi-point test, prior to or during the first three calendar months of production, and report in AOF.PAS format.

A deliverability test is a test to predict the absolute open flow potential (AOFP) of a well, and its deliverability potential under various pipeline backpressures. A deliverability relationship is needed because a gas well may not be producing at capacity. A gas well's deliverability is a function of wellbore configuration and gathering system back pressure, and requires a stabilized flow rate.

A stabilized rate is required to be a calculated value, based on the time to pseudo steady state. This calculation corrects the actual extended test rate to a lower estimated stabilized rate. Higher permeability reservoirs will have very little correction to stabilize, where lower permeability reservoirs will have a large correction. Although the time to pseudo steady state varies with the well geometry and reservoir shape, one can assume a well in the center of a one-section drainage area for a gas well; or if the data or mapping suggests a different drainage area, adjustments must be made as indicated in section 5 of EUB Guide 3 *"Gas Well Testing Theory and Practice"*.

This Guide recognizes concerns regarding the flaring or venting of gas during an initial test, and the validity and cost of repeated deliverability tests. Therefore, the

above requirement strives to obtain the most practical test design and early production forecasting. The type of deliverability test, single or multi-point, is left up to the licensee/operator. More information is available in section 4.3.1 below.

The licensee uses this information to assess tubing string design, determine the economics of tying in a well, to size surface processing facilities, and pipeline gathering systems. The EUB uses this information in reserves determination, provincial forecasts of gas deliverability, and in processing applications for gas plants, pipelines, batteries, etc. In addition, this data is made available to the public for multiple purposes, including drilling release rate calculations, property evaluation.

Further deliverability testing is not required, providing a reliable long-term relationship is determined by the above methods, and the EUB has not defined special needs. Some suggestions for test design are included in the following sections.

There is no deliverability test requirement for oil wells but where such tests are run they must be filed with the EUB, as per section 11.120 of the Oil and Gas Conservation Regulations.

4.3.1 Recommended Practices for Gas Well Deliverability Tests

In-Line Testing Should Always be the Preferred Option After Appropriate Clean-up

To determine the type of deliverability test to conduct, consider.

- Public/environmental impact of the test atmosphere.
- The primary objectives of the test.
- The magnitude of data needed (i.e., multi-point versus single-point, surface versus bottomhole).
- The type of reservoir (permeability, drive mechanism).
- Test rates and flow periods must be designed to minimize flaring (see section 4.4 for more information on flaring and emissions).
- The initial test should be a multi-rate test when the anticipated AOFP of the well is 300 e^3m^3/d (10.6 MMscfd) or greater, or if turbulence is a factor.
- Tests which involve flaring are not intended to provide reservoir limits information, only to prove sufficient reserves to warrant expenditures for tie-in and facilities. Section 4.2.2 *of The Petroleum Society Monograph Number 1, Determination of Oil and Gas Reserves* states that "Five to ten per cent of the oil or gas must have been produced before a reasonably accurate calculation can be made".

4.3.2 Types of Deliverability Tests

The main types of deliverability tests used today are:

Flow After Flow Test: requires a static reservoir pressure and stabilization of three to four flow rates. This test provides good radius of investigation, but often results in a lengthy test, resulting in excessive flaring of gas. For this reason, this test is best for use in high permeability reservoirs that stabilize quickly, otherwise serious consideration should be given to testing in-line.

Isochronal Test: requires a static reservoir pressure, a flow period of fixed duration, followed by shut-in until pressure stabilizes again. This sequence of flow and build-up to stabilized pressure is repeated with only the final, or extended flow rate required to stabilize. This test is still quite lengthy, and again best suited to high permeability reservoirs.

Modified Isochronal Test: requires a static reservoir pressure, then flow and shut-in periods of equal duration. This method was developed for testing tight reservoirs, but is often used today on high volume, tubing restricted and/or partially penetrated wells with fair to good permeability.

Single Point Test: requires a stabilized rate and flowing pressure measured before the well is shut in and built up to a stabilized reservoir pressure. This test is widely used for deliverability tests where the turbulence factor is known; usually for subsequent tests on a well, for initial tests in a relatively mature pool, or where deliverability may be poor or flow conditions are predetermined by pipeline or plant restrictions.

A build-up test conducted with any type of deliverability test, will provide information on current reservoir pressure, permeability, formation flow capacity, apparent skin and reserves should depletion be detected. A multi-rate deliverability test will indicate the effect of pressure loss due to turbulence.

Other considerations when designing a deliverability test:

- environmental and safety requirements (See new *"Upstream Petroleum Industry Flaring Guide")*,
- expected H_2S percentage/maximum release rates,
- flare dispersion modeling (flare stack design and cumulative assessment as per section 4.4.3 of this Guide),
- flare efficiency (if flaring),
- down wind monitoring needs,
- surroundings, inhabitants, cottage country,
- time to stabilization (permeability),
- flow rates, restrictions and duration of flow (higher rates do not necessarily increase the radius of investigation – see EUB Guide 3 for further information),

- backpressure,
- turbulence effects,
- well depth,
- wellbore configuration (hydrate range, liquid loading, clean-up needs, etc.),
- type of stimulation,
- fluid analysis needs,
- coning/drawdown limitations,
- test equipment sizing,
- wellbore storage (downhole shut-in tool),
- interference effects/other producers in the area, and
- gauge pressure rating should be matched to expected flowing and reservoir pressure
  - a high pressure gauge in a low pressure reservoir may cause stairstepping and introduce noise affecting derivatives used in test interpretation
  - a low pressure gauge in a high pressure reservoir will compromise the mechanical integrity of the gauge.

It is recommended that a second deliverability check be conducted after a well stimulation treatment, as follows:

- obtain a flowing bottomhole pressure using a properly calibrated subsurface gauge, in most cases, during a period of stabilized flow,
- the flowing pressure should be taken just prior to shutting the well in for its second pressure survey, and
- if the stabilized flow is interrupted in order to run subsurface gauges, production should be resumed at the previous stabilized rate for about 10 times the interruption, to obtain the flowing pressure.

Whenever possible, product content tests, a second deliverability check, and a second pressure survey should be scheduled together.

The general practices in EUB Guide 3 should be followed.

4.3.3 Surface Testing Dry Gas Wells

In order to estimate a stabilized pressure or the productivity/absolute open flow potential of a gas well, it is necessary to determine the bottomhole pressures at static and flowing conditions, either by actual measurement with a bottomhole pressure gauge, or by calculation from wellhead pressure measurements. Recognizing that in lower productivity gas wells it is often not cost effective to measure static and flowing pressures by downhole gauge, estimations may be made from wellhead data, gathered by accurately calibrated deadweight gauge.

The calculation of a bottomhole pressure from data measured at the wellhead involves the solution of the energy balance equation as applied to both static and moving columns of gas. There are several methods available for this solution and reference should be made to EUB Guide 3. This pressure must be reported in the AWS.PAS format to meet the initial pressure requirement.

The calculation for a single-phase fluid (gas) in the wellbore, requires knowledge of the wellhead pressures, the properties of the natural gas, the depth of the well, flow rates, formation and wellhead temperatures, and the size of the flow lines. Appendix B of Guide 3 introduces the theory and basic equations relating these quantities. Methods utilizing the basic equations and simplifying assumptions to make them practical are outlined. The recommended procedure is discussed in detail and is illustrated by appropriate examples.

Also included in Guide 3 is a simple method for the estimation of bottomhole pressures for gas-condensate wells.

4.3.4 Relaxation of Sandface AOF Requirement

The need for deliverability data diminishes as the potential of a gas well drops. Where a stabilized wellhead absolute open flow potential (WAOFP) is 20 e^3m^3/d (~710 Mscfd) or less, and where liquid loading does not mask the well's downhole potential, the wellhead and the sandface deliverability potentials are close enough to be considered the same. In such cases, a single point wellhead deliverability relationship is acceptable, using an inverse slope of "n" = 1.0. Such cases should be indicated in "Remarks" to ensure the requirement for the sandface deliverability test is waived.

There may be instances beyond the 20 e^3m^3/d rate where a sandface AOF is not necessary. This could occur in a well established area, where there is sufficient deliverability data to correlate from sandface AOFs to surface data. In these instances, licensees are encouraged to make application to increase the 20 e^3m^3/d limit. Such applications should be made on a pool/area/field basis, on higher rate, low-pressure wells, where production is unrestricted. Applications must include a correlation between actual measured sandface and surface data, and must address issues like tubulars, restrictions, etc. A fluid shot should always be used to indicate the absence of liquid in the wellbore.

The EUB will gather data from these applications for consideration by the Committee (and any other interested parties), to define the future direction of this requirement.

4.3.5 Exemption from Initial Deliverability Requirements

Exemption from initial deliverability requirements, similar to the South Eastern Alberta Shallow Gas system, will continue to be administered on an application basis. (In 1998 approval was granted for exemption of this requirement on infill wells in the Provost Viking, Belly River, Basal Colorado & Mannville MU #1 Pool). Such application may be made for well-established areas, with substantial historical data available. It is the Committee's intention to gather information from these applications to enable future definition of criteria for exemption or relaxation of requirements.

These applications may be made on a well or a pool basis and should include:

- correlation of historical pressure and deliverability data, establishing predictable trends,
- consistencies across the field/area, and
- production trends.

These applications will be available upon request to: welltest-helpline@eub.gov.ab.ca.

4.3.6 Reporting Deliverability Tests

Requirement:

All deliverability tests conducted must be submitted in the AOF.PAS electronic format, as defined in Guide 52. A PRD.PAS file must be submitted for all tests involving flaring and any other test where production testers have been used.

The initial deliverability requirement will not be considered fulfilled until/unless AOF.PAS and PRD.PAS files have been submitted and accepted by the EUB, as indicated above. The most current version of all PAS formats is available on the EUB website at:

www.eub.gov.ab.ca/bbs/dds/welltest/welltest.htm

Failure to comply with this requirement will result in compliance measures as detailed in section 6 of this guide.

Requirement:

"You must file an S-1 statement for a well that has produced any fluid (crude oil, crude bitumen, condensate, gas, or water) for any reason, reporting the volumes produced, regardless of the requirement for filing an S-4 statement." When an S-1 statement is filed, an S-2 statement must also be filed.

The above is an excerpt from Appendix 4 of EUB Guide 7 "*Production Accounting Handbook*", and is interpreted by the EUB to include cleanup and test volumes, whether flared, vented, or produced in-line.

These volumes and the method of production (flared, vented, or in-line) must also be reported in the AOF.PAS electronic report.

4.4 Flaring and Emissions During Well Testing

Flaring Must Always Be Kept to a Minimum

Requirement:

- **The flaring of any gas where the hydrogen sulphide content equals or exceeds 50 moles per kilomole (5 per cent), requires a written approval from the EUB (Environment, Safety & Technical Services Group) as per section 15.240 of the Oil and Gas Conservation Regulations.**
- **The flaring of gas where the hydrogen sulphide content is less than 50 moles per kilomole (5 per cent), must be conducted in accordance with IL 91-2.**
- **An approval from the EUB (Systems and Resource Information Group) is required if the total volume flared is expected to exceed 600 e^3m^3.**

See sections 4.4.1 and 4.4.2 for further information.

In January 1999, the EUB gathered statistics based on 2695 deliverability tests that had been submitted in the previous year, that had reported volumes and methods of production. Of these tests:

- 55 per cent of the tests were flared,
- 16 per cent of the tests were vented, and
- 28 per cent of the tests were produced in-line.

The total volume of gas produced during these tests was 804 e^6m^3

- 32 per cent of the volume was flared,
- 3 per cent of the volume was vented,
- 65 per cent of the volume was produced in-line, and
- the average volume of gas flared per test was 173 e^3m^3 .

With electronic reporting this informtion is mandatory and will be correlated and made available each year. The above information will be used as a baseline to mark progress in the area of flaring/emissions.

Since the gas is the sole commodity or revenue generator when testing a gas well, the natural economic incentive to not flare more than necessary should keep the volumes as low as possible. Licensees must ensure that tests are well designed to minimize flaring and lost production.

Tests involving flaring are not intended to be reservoir limits tests, only to prove sufficient reserves to warrant expenditures for tie-in and facilities. Section 4.2.2 of The Petroleum Society Monograph Number 1, *"Determination of Oil and Gas Reserves"* states that **"Five to ten per cent of the oil or gas must have been produced before a reasonably accurate calculation can be made."**

Well testers must continually look at new technologies to reduce the amount of flaring for environmental and conservation reasons. The EUB encourages licensees to test in-line wherever possible. If this results in a delay in submitting the initial deliverability test, approval for an extension can be obtained via e-mail to the Well Test Helpline at:

welltest-helpline@eub.gov.ab.ca (see Appendix C for contacts).

Where gathering and processing infrastructure are in close proximity, the EUB expects operators to recover well test gas as an alternative to flaring. The EUB recognizes that temporary connection to gathering systems and possibly temporary compression or other facilities will be required to conserve well test gas. To facilitate conservation of new well test gas, the EUB will not require facility approvals for related facilities including compressors. It is noted that:

- Well test approvals are required as described in section 3.1 of the new *"Upstream Petroleum Industry Flaring Guide"*. Applications to the EUB Resources Division, Systems and Resource Information Group for volumes exceeding 600 e^3m^3 must note the operator's intent to install temporary facilities and must list the facilities to be used.

- The temporary equipment must not be operated for more than 14 days in total. Allowance may be made for downtime during the testing period. In general, only one such test period will be approved at each site. An application, as described in EUB Guide 56 will be required, if extended tests or multiple tests are planned that will require more than 14-day operation for the temporary facility.
- Temporary surface facilities must be removed from the lease within 30 days of completion of the test.
- Temporary facilities must meet noise control requirements defined in ID 94-4.
- Requirements, including public notification, as defined for well test flaring in section 7.060 of the Oil and Gas Conservation Regulations and section 3.1.3 of the new *"Upstream Petroleum Industry Flaring Guide"* must be met.
- Operators must have appropriate emergency response plans in place for sour wells.
- Temporary facilities, including pipelines, must meet applicable technical standards and codes and must comply with applicable EUB, environmental, and safety regulations.
- Temporary sweetening processes, if used, must be of the non-regenerative (e.g., zero sulphur emissions) type. Temporary installation of a regenerative sweetening process with acid gas flaring will require a facility application as described in EUB Guide 56.

  Under current regulations, all temporary or permanent sweetening facilities, including non-regenerative types, require AEP gas processing plant approvals.

For further information see section 3 in the forthcoming *"Upstream Petroleum Industry Flaring Guide".*

4.4.1 Flaring of Sour Gas (H_2S Content => 50 Moles per Kilomole)

All requirements dealing with sour gas are set out in the Oil and Gas Conservation Regulations, and are summarized in the forthcoming *"Upstream Petroleum Industry Flaring Guide"*. Section 7.055 of the Oil and Gas Conservation Regulations requires that a permit be obtained to flare gas containing 50 moles per kilomole or greater of H_2S or for any well classified as a critical well. Section 15.240 of the Oil and Gas Conservation Regulations summarizes the information to be submitted prior to obtaining a permit. Section 7.060 details other requirements including required fluid analysis testing and public and EUB notification.

4.4.2 Flaring of Gas Where H_2S is < 50 Moles per Kilomole

Flaring of sour gas volumes less than 600 e^3m^3, and containing less than 50 moles per kilomole of H_2S may be conducted without application or written approval of the EUB, provided the requirements set out in IL 91-2 are met.

EUB approval is required to flare any volumes of gas that exceed 600 e^3m^3 which contain less than 50 moles per kilomole of H_2S. These applications can be submitted by phone to 297-4424, or e-mailed to the Well Test Helpline.

Applications must include the following information:

- licensee name,
- company representative,
- phone number,
- e-mail address,
- date of request,
- well location,
- volume requested,
- H_2S content,
- maximum flow rate,
- dates flaring to occur,
- distance to nearest resident,
- distance to tie-in,
- special conditions,
- estimated pressure transient behaviour of the reservoir using the "test design" module found in most pressure transient well-test software (Horner, Cartesian and Log/log outputs), and
- consideration of alternatives to flaring.

4.4.3 Flare Stack Design and Operations

Operators are expected to design, operate and maintain flare systems to safely dispose of gas that must be released to the atmosphere. EUB minimum requirements for the design and operation of flare systems have been established and are included in the following requirements. In addition, the Board expects that operators will use good engineering practice in the design and operation of flare systems as outlined in the CAPP *"Recommended Practices for Flaring of Associated and Solution Gas at Oil Production Facilities"* and in API Recommended Practice 521, section 4 *"Selection of Disposal Systems"*.

Industry must comply with the following requirements for flare systems installed at well testing locations, wellsites, oil batteries, gas batteries, and gas processing plants unless otherwise noted.

4.4.3.1 Ignition

- A flame must be present whenever hydrocarbons or acid gases, in excess of amounts that are permissible to vent (see section 8.0 of the *"Upstream Petroleum Industry Flaring Guide"* for further information), are directed to flares. Acid gas and intermittent sour

gas flares are required to have reliable pilot and automatic ignition devices to ensure continuous ignition of any gas discharged to the flare.

- manual flare ignition, subject to adequate safety and forest fire prevention considerations, may be accepted for blow-down stacks or
- flares installed for maintenance purposes where no continuous gas flow exists or where no automatic relieving systems are connected to the stack.

4.4.3.2 *Flame Stability*

Flame stability and combustion efficiency are related to the heating value of the combined flare gas stream. Existing requirements, including the typically specified minimum heating value for flared acid gas streams of 9 MJ/m^3 and the US EPA minimum guideline for air or steam assisted flares of 11.2 MJ/m^3 have been reviewed in light of current research being conducted at the University of Alberta. The results of this research clearly indicate that gases diluted with CO_2 (e.g., acid gas) do not support stable flames under cross wind conditions if the heating value is less than 20 MJ/m^3. The following requirements are based on current research findings and may be revised, as additional research results become available.

- Sufficient fuel gas must be added to routinely flared sour, acid or other low heating-value gas streams to ensure that the net heating value of the combined stream is at least 20 MJ/m^3 or such higher value as is required to ensure compliance with Alberta Ambient Air Quality Guidelines or specific EUB or AEP approvals.

- Flare stacks must have sufficient exit velocity or must be provided with suitable features to prevent wind from extinguishing the flame of low or intermittent flows of sour or acid gases (e.g., wind guards).

As a guideline, most routine flares will be relatively stable if stack exit velocities are greater than 1 to 2 m/s and less than 18 m/s. Higher exit velocities, up to 122 m/s, may be acceptable if actual exit velocity is less than the maximum exit velocity (V_{max} in m/s) as determined by the following relationships for flared gas net heating value H_T in MJ/m^3.

- Steam and non-assisted flares:
  Log 10 (V_{max}) = (H_T + 28.8) / 31.7

- Air assisted flares: V_{max} = 8.706 + 0.7084 (H_T)

4.4.3.3 Stack Height

- Flare stacks must be designed so that the maximum radiant heat intensity at ground level will not exceed 4.73 kW/m^2. Unless otherwise specified, ground level radiant heat determinations will be based on calculation procedures outlined in API Recommended Practice 521, section 4.4.2.3 or GPSA Engineering Data Book (Eleventh Edition), section 5.

- Flare stacks located within a distance equivalent to five times the height of nearby buildings must have a height of at least 2.5 times the height of the highest building.

- Flare stacks for acid gas or sour gas containing more than 10 moles of H_2S per kilomole of gas must have a height of at least 12 metres above ground level or such greater height as may be required by Item (1) above or as required to provide adequate plume dispersion to comply with Alberta Ambient Air Quality Guidelines for SO_2 and H_2S (refer to section 7.4 of the *"Upstream Petroleum Industry Flaring Guide")*.

4.4.3.4 Emergency Sour and Acid Gas Flaring Procedures

In some instances where volumes and flare rates are very large it is not practical to design flare stacks with sufficient height and to add sufficient fuel gas to permit continuous emergency flaring in compliance with the Alberta Ambient Air Quality Guidelines at full sour raw or acid gas production rates.

If, based on evaluation procedures described in section 7.4 of the *"Upstream Petroleum Industry Flaring Guide"*, a sour or acid gas emergency flare is not of sufficient height to meet the one hour Alberta Ambient Air Quality Guidelines for SO_2 under high flow rate conditions, then operating procedures and/or automatic shut-downs must be in place to immediately curtail production and control flaring to comply with the one hour guideline. Automated shutdowns are expected to be installed in semi-attended facilities to ensure compliance with this requirement. This requirement takes precedent as applicable, over flare reduction requirements listed in

Table 1, section 2.6.1 of the *"Upstream Petroleum Industry Flaring Guide"*.

4.4.3.5 Liquid Separation

Entrained liquids in flare streams are recognized to reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons and products of incomplete combustion. To reduce and/or eliminate these effects, the EUB requires:

- If liquid hydrocarbons, water or other liquids are present in flare gas sources, it is required that adequately designed, operated and maintained liquids separation equipment be provided in both temporary (well test) and permanent flare systems.
- Flare system piping and all piping related to the liquids control system must be engineered to prevent retention of liquids by ensuring that piping is sloped to drain to separators and to avoid low-point liquid traps.
- The flare separator must be designed to provide adequate separation of liquid and large liquid particles that are entrained in the gas. Liquid hydrocarbons must not be flared.
- The flare separator or knockout drum must be designed to have sufficient holding capacity for liquids that may accumulate as a result of upstream operations such as hydrocarbon carryover, liquid slugs and line condensation. The flare separator must be designed such that the ability of the vessel to separate liquids from the gas stream is not impaired at the maximum design liquid level.
- Design of the flare separator must ensure that no re-entrainment of separated liquids will occur at maximum expected flare gas flow rates.
- Flare separators must be provided with visual level indicators, high level alarms or operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level during all operating conditions.
- A high level alarm must be installed on flare separators or flare knockout drums where liquid streams are

directed to the separator for retention or where free liquids are expected in continuously flared streams. The flare separator high level alarm must be connected to facility alarm panels and/or semi-attended facility alarm call-out systems if the facilities are so equipped.

- The flare system and separator or knockout drum must be designed and operated to ensure that effectiveness will be maintained under all operating scenarios and weather conditions (e.g., freeze protection is required).
- The flare separator or knockout drum must be designed to the ASME Boiler and Pressure Vessel Code if the maximum pressure due to the flow resistance in flare system is sufficient to trigger this requirement.
- Flare separator or knockout drums used for liquid storage must be designed and operated to meet the requirements listed in EUB Guide 55 for above ground or below ground storage tanks as is appropriate.

4.4.3.6 Spacing Requirements

- Flare stacks must be located at least 100 metres away from an occupied residence.
- Flares must be located, designed, and operated so that no hazard to public property or forest cover will be created. Flares must be located at least 100 metres away from surfaced improvements with the exception of surveyed roadways.
- Flares must be located at least 50 metres away from wells or flammable liquids storage tanks and at least 25 metres away from any oil or gas processing equipment.
- The following requirements are defined in the Forest and Prairie Protection Regulations (AR 135/72):
  - Areas within 30 metres of flare pits must be cleared of all combustible debris,
  - Clear, bare mineral soil surface must be maintained within 8 metres of flare pits
  - In forested areas, flare stacks must be located at least 2.5 times the stack height, or such other distance as prescribed by a forest officer, from combustible debris.
- To obtain information during such times as Fire Bans or if there is reason to believe Fire Bans are in effect contact the following two agencies:

- www.gov.ab.ca/env/forests/fpd/fco2.html go to 'fire control orders', for fire ban information and regions affected as per Alberta Environment Protection,
- phone (780) 427-fire (3473) Alberta Environment Protection, or
- the local Municipal District must also be contacted for their respective fire ban requirements.

4.4.3.7 Noise

Flare systems must be designed to operate in compliance with current revision of the EUB's Noise Interim Directive. Routing and emergency flare conditions are to be considered in noise impact assessments required by the ID 94-4.

4.4.3.8 Visible Emissions

Smoke from flares must not exceed 40 per cent opacity averaged over six consecutive minutes as specified in the Alberta Environmental Protection and Enhancement Act (EPEA), Substance Release Regulations, or as specified in EPEA approvals, whichever is more stringent.

4.4.4 Dispersion Modeling Requirements for Sour or Acid Gas Flares

SO_2 and H_2S emissions from flaring, incineration, or combustion of sour or acid gas have potential for adverse effects. Therefore, the design and operation of stacks must consider air quality impacts of sulphur emissions from the stacks taking into account other sulphur emission sources in the area.

Operators must demonstrate, by AEP accepted dispersion modeling methods, that SO_2 and H_2S emissions from flaring, incineration, or combustion of sour or acid gas will not result in exceedance of Alberta Ambient Air Quality Guidelines if the gas contains greater than or equal to:

- ten moles of H_2S per kilomole of gas; or
- one tonne per day of sulphur.

Operators flaring gas below the above criteria may wish to consider dispersion modeling as part of their respective environmental due diligence processes.

4.4.4.1 Definitions

- Screening Assessment – this is the quickest and simplest modeling approach. Screening assessments usually provide a

conservative estimate of downwind concentrations. If exceedances of ambient air quality guidelines are predicted by a screening assessment, then a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the Alberta Ambient Air Quality Guidelines.

- Refined Assessment – this is a more complex and data intensive level of modeling. Refined assessments more closely estimate actual air quality impacts by using actual meteorological data. An appropriate model should be selected and this choice must be defensible. The applicant must demonstrate that the completed work follows accepted methodologies and standards.

4.4.4.2 Modeling Assumptions

Ambient air quality modeling will observe the following assumptions for screening assessments:

- stack specific terrain extracted from 1:50 000 topographical maps or equivalent,
- full meteorology (e.g., select this option for SCREEN input; it is the SEEC default),
- rural dispersion conditions (e.g., "rural" is to be selected for SCREEN or ISCST options or roughness class 1 is to be selected for SEEC), and,
- partial conversion of H_2S to SO_2. Until such time as combustion efficiency can be reliably estimated based on design conditions, ambient air quality modeling evaluations will assume a 98 per cent molar conversion of H_2S to SO_2 (e.g., 100 moles of H_2S yields 98 moles of SO_2 plus 2 moles of H_2S and only 98 per cent of the available combustion energy is released as heat).

4.4.4.3 Individual Source Modeling Approach

- Initial modeling can be conducted using a screening assessment. Simple terrain modeling assumptions can be used for situations where terrain elevations are less than the plume height; otherwise complex terrain modeling assumptions must be used. The selected flare height must not result in maximum hourly average ground level SO_2 or H_2S concentrations in excess of the Alberta Ambient Air Quality Guidelines. A refined assessment can be used if the screening assessment results in an impractical stack height. Modeling should address maximum hourly flow rate conditions.

- If the predicted maximum hourly average ground level concentrations using the screening model are less than one-third of any of the related Alberta Ambient Air Quality Guidelines, no further modeling is required.

4.4.4.4 SO_2 Cumulative Effects Assessment

If individual source model predictions exceed one-third of the Alberta Ambient Air Quality Guidelines for SO_2, the applicant is required to consider the combined effect of other sources in the area. The following steps should be followed:

- Repeat the screening dispersion modeling using the flat terrain assumption (if necessary).
- Identify the farthest downwind location where predictions exceed one-third of the hourly average Alberta Ambient Air Quality Guideline for SO_2 to define the radius of influence.
- Identify all other sources of the pollutant located within this radius of influence (if there are no other sources of the pollutant within the radius, no further modeling is required).
- Quantify the emissions of the pollutant from these other sources and obtain all necessary input data, such as stack height and other parameters (the EUB expects operators to share related data on a timely basis). Maximum hourly flare flow rate conditions must be used for all sources in the radius of influence.
- As a screening approach, separate flat terrain screening model runs are to be performed for each of the sources within the radius of influence.
- If the sum of the predicted maximum ground level concentrations for all sources, regardless of location, is less than the Alberta Ambient Air Quality Guideline for SO_2, no further modeling is required.
- If the sum exceeds the Alberta Ambient Air Quality Guideline, a refined modeling approach will be required to prove that the guideline is not exceeded and to determine the appropriate stack heights required to meet the guideline. All refined modeling must follow the methods outlined in AEP's Draft Air Quality Model Guidelines.

It should be noted that the flat terrain assumption is used to simplify the cumulative effects assessment only. Where complex terrain exists, the final stack height for the source under consideration will be the greater of that determined by single source modeling with

of that determined by single source modeling with complex terrain (as above) and by cumulative effects assessment in this section.

4.4.5 Limitations on Venting

The restrictions on venting are currently under review and will be addressed in the new *"Upstream Petroleum Industry Flaring Guide"*. For companies tracking greenhouse gas emissions, venting leads to higher equivalent CO_2 emissions and for that reason is discouraged. However, where it is not practical to recover or flare gas, the EUB may accept venting of small volumes of gas.

Venting of gas is governed by the following principles and requirements:

- if continuous vent volumes are sufficient to support combustion, gas gas will generally be burned in a flare,
- gas will not be vented if it constitutes an unacceptable fire or explosion hazard on or off the facility lease,
- no venting of H_2S and other total reduced sulphur compounds to the atmosphere is permitted, and venting must not result in exceeding Alberta Ambient Air Quality Guidelines for H_2S,
- as per section 7.070 of the Alberta Oil and Gas Conservation Regulations, stock tank vapours and other gas emissions from batteries receiving gas or having vapours containing more than 10 moles per kilomole H_2S must be burned,
- venting of gas containing H_2S and other compounds must not result in odours outside the lease boundary,
- the true vapour pressure of hydrocarbon product stored in atmospheric storage tanks shall not exceed a true vapour pressure of 82 kilopascals where such tanks are vented to the atmosphere,
- the volumes of gas where venting is permitted is still under review and will be detailed in the new *"Upstream Petroleum Industry Flaring Guide"*,
- appropriate flame arrester or equivalent safety device must be used on all vent lines from oil storage tanks which are connected to flare stacks (see Oil and Gas Conservation Regulation 8.090 (7)),
- vented gas from gas dehydrators is subject to limitations on benzene emissions as detailed in IL 97-4, and

- if operators have reason to expect that the benzene content of vented gas exceeds 5.0 moles per kilomole, then **site vent gas** benzene emissions must be assessed and, if necessary, controlled so that total benzene emissions for the facility or lease site will not exceed:

  - 3.0 tonnes per year for facilities commissioned prior to 1 January 1999 and located within 0.75 kilometres of a residence, effective 1 January 2001

  - 3.0 tonnes per year for facilities commissioned after six months from the issuance of the *"Upstream Petroleum Industry Flaring Guide"*; and,

  - 5.0 tonnes per year for facilities commissioned prior to the issuance of the *"Upstream Petroleum Industry Flaring Guide"* effective 1 January 2001.

4.4.6 EUB Monitoring of Flaring and Venting

The EUB gathers data from each test and will administer flaring and venting as follows:

- The EUB gathers sufficient data to determine what tests require permits or approvals and will administer accordingly.

- If flaring is completed without approval and notification, the licensee will be required to provide an explanation, as well as what steps have been taken to ensure the proper procedures will be followed in the future.

Compliance will be monitored on an audit basis, with consequences as detailed in the EUB's generic compliance ladders. Escalating consequences will apply to subsequent occurrences. See section 6 of this Guide for further information on compliance.

4.5 Annual Pool Pressure Surveys

Requirement:

Annual surveys are required on oil and gas pools, as specified in the annual survey schedules as follows:

- **Survey 25 per cent of the producing well count based on quarter section spacing in OIL POOLS (e.g., One survey per producing section), and**
- **Survey 25 per cent of the producing well count based on one section spacing in GAS POOLS.**

Tests intended to fulfil survey requirements must meet the standards set for "acceptable tests" as defined in section 5 of this guide.

It is the responsibility of the Coordinating Operator to ensure these requirements are met, or to address any inaccuracies with EUB Well Test staff (e.g., change of licensee responsibility due to sale of property, or a change in productivity or recoverable reserves). Full details on licensee/operator responsibilities are found in section 4.5.5 of this guide.

4.5.1 Developing the Survey Schedules

Pressure data is considered most important in the initial and developing years of oil or gas pools, to assist in determining pool delineation, reserves, recovery mechanism, waterdrive or influx activity, and optimum depletion strategy.

The parameters considered by EUB staff when adding new oil or gas pools to the survey schedules are:

- EUB's recoverable reserves (for larger pools, see EUB publication ST-1 *Alberta's Reserves*),
- number of productive wells,
- existing pressure data,
- productivity,
- fluid density,
- unique reservoir characteristics,
- specifics to the area, and
- the need for the data.

These parameters are reconsidered each year. Therefore, a pool may be added to the survey schedule if productivity has increased, if new development has occurred in an existing pool; or it may be deleted if the pool now qualifies for advanced depletion. In addition, special needs are identified and pools are added through the application process, to monitor equity issues, enhanced recovery feasibility, progress of enhanced recovery schemes, concurrent production, good production practice, special allowables, etc. These special needs will be a condition of the approval or the letter of disposition.

Only those pools that meet the following criterion are added to the survey schedule, unless a special need has been identified:

	Oil Pools	Gas Pools
Recoverable Reserves	=> 15 e^3m^3 (94 347 bbl)	=> 30 e^6m^3 (1.06 bcf)
Well Productivity	=> 5 m^3/day	=> 5 e^3m^3/day
Stage of Depletion	< 50%	< 50%
Oil Density	<= 925	

Pools that do not meet the above criterion and where no special need has been identified, will not appear on the survey schedule, and do not require testing. However, any tests conducted on any well/pool must be submitted to the EUB. Any new wells drilled into these pools, will be subject to initial testing requirements as per sections 4.2 and 4.3.

Once the survey schedule has been published for the year, no pool will be added to the survey schedule for that year without written notification to the coordinating operator. The next update of the schedule on the EUB website will include that pool.

Due to the need to define the pools requiring surveys very early in the year, it is necessary to assess the productivity based on the previous year's production. If a well/pool has declined to below the minimum productivity rates indicated above, it may be appropriate to review the survey requirement and apply for relaxation. However, to qualify for this reduction, all wells in the pool must have limited production, as exemption will not be given for individual wells or portions of pools.

Due to the timing of the survey schedule, a well could appear on the survey schedule that has since suspended production, or declined to below the criterion listed above. As long as the pool is on the survey schedule, the licensee is responsible for testing, or requesting that the pool be removed from the survey schedule. This can be done by contacting the EUB Well Test Section as per Appendix C.

4.5.2 Special Circumstances

Some oil and gas pools have special circumstances defined and will be identified with a survey frequency of "SPECIAL CIRC" on the survey schedule. These circumstances are usually defined through the approval process and the letter of disposition, but the particulars will be identified in Appendix I to the survey schedule.

Situations which result in special circumstances being assessed are:

- oil pools
  - approval clauses for enhanced recovery, good production practice, concurrent production, etc.
  - partial pool requirement
  - special areal coverage requirement
  - specific wells that require monitoring

- gas pools
  - off target wells
  - acid gas disposal wells
  - gas cycling schemes
  - gas storage wells

4.5.3 Publication of Survey Schedules

The survey schedules are published early each year, usually in January, and Industry is notified of availability by EUB Public Notice. The survey schedules are posted on the EUB website, complete with current status (e.g., received, outstanding, partially received, not required, etc.). This file will be updated around the 20th of each month, and every second week from November to April. For further information on accessing this file, see section 4.5.4 below. Hard copies of the oil and gas pressure survey schedules are available through the EUBs Information Services section, free of charge.

It is the Coordinating Operator's responsibility to determine the pools for which he is responsible, and contact the other operators in the pool to coordinate the survey. There is a sample letter included in this guide that can be used for this purpose (see Attachment I). See section 4.5.5 for more information on the responsibilities of the Coordinating Operator.

4.5.4 Extracting Annual Survey Schedule Information from the Internet

The survey schedules for oil and gas pools, are available on the EUB's website at

http://www.eub.gov.ab.ca/bbs/data/welltestreq.htm

4.5.5 Licensee/Operator's Responsibilities

Requirement:

Where more than one licensee/operator produces from the same pool:

- **A Coordinating Operator will be designated and deemed responsible for coordinating the surveys for the pool, and ensuring the pool's survey requirements are fulfilled as required by this Guide.**
- **All licensee/operator(s) in a pool are required to cooperate with the Coordinating Operator in planning, conducting, and submission of pressure survey data sufficient in quantity and quality to fulfil the pool's survey requirements as required by this Guide.**

All parties that obtain revenue from a pool are expected to share the burden of testing. A cooperative approach to pressure testing should result in the best well selection and the lowest costs, therefore, every effort should be made to develop a single coordinated program.

A Coordinating Operator will be designated for each pool on the survey schedule. The EUB program selects the Coordinating Operator automatically as the operator who produced the largest total volume of oil or gas from the pool in the previous year. The Coordinating Operator is the EUB's primary contact for testing in a pool, as well as being deemed responsible for ensuring the pool's survey requirements are fulfilled.

The main duty of the Coordinating Operator is to develop and coordinate pool pressure survey programs with the input and assistance of the other licensees/operators in the pool. The Coordinating Operator should always be cognizant of opportunities that permit timely pool pressure surveys to be conducted during scheduled shut downs and plant turn-arounds.

Attachment I is a sample letter which can be used by the Coordinating Operator, to initiate input and cooperation from the other licensees/operators

in the pool. An example of the procedure for developing a pressure survey program for a pool is given in section 4.6.11 Recommended Practices.

If a Coordinating Operator has fulfilled their part of the requirements, but their efforts to coordinate the survey with the other licensees/operators have been to no avail, they may provide the EUB with documentation of communications (e.g., copies of letters, e-mails, documentation of telephone calls, etc.). The responsibility will then shift to the uncooperative licensee/operator(s). Again, the survey schedule and the current status for each pool is on the EUB website to assist the licensees/operators in ensuring the survey requirements are fulfilled, as referenced in section 4.5.4 of this Guide.

4.5.6 Licensees' Responsibilities when Buying/Selling Wells

It is the responsibility of the licensees, both the seller and the buyer, to ensure a proper well license transfer is filed with and approved by the Liability Management Team of the EUB's Corporate Compliance Section. If the seller of the property is the Coordinating Operator, it is their responsibility to advise the EUB Well Test Section of the change of responsibility to avoid assessment of non-compliance fees. The EUB considers the original licensee responsible until this process is complete (see ID 93-2 for more information).

If the previous licensee receives a notice letter, they are expected to contact the EUB Well Test staff within the timeframe specified in the warning or notice letter. Failure to do so, will result in the assessment and liability of a $1000.00 non-compliance fee.

4.5.7 Determining the Number of Surveys Required

Having regard for testing costs and adequate pressure coverage, the minimum number of pressure surveys should equal about 25 per cent of a pool's producing well count, based on quarter section spacing for oil pools. This translates to one survey per productive section. For gas pools, one survey per four productive sections is required. This does not necessarily mean that only productive wells should be surveyed, or that a well must be surveyed in every productive section for oil wells (e.g., if there is only one productive well in a section, an offset well is acceptable).

Many oil and gas pools are single well pools. For these pools, the 25 per cent rule may be interpreted as one pressure survey every fourth year, once the initial survey requirements have been fulfilled. Similar interpretations can be applied to two well pools for "biennial" survey frequency.

It is important to remember that the initial pressure requirement would still apply to any new wells drilled into these pools. Three and four well pools on the survey schedule would require annual surveys as a minimum, based on

normal spacing (quarter section for oil pools and one section for gas pools, assuming no special needs have been identified).

4.5.8 Selecting Wells to be Surveyed

It is usually considered impractical to shut in an entire pool to conduct a pressure survey. However, if interference is a problem, it may be advisable to shut in offset wells for the duration of the test.

Costs are significantly reduced if some pressures from new or shut-in wells are used to meet the requirements, provided they are representative of the producing portion of the reservoir. For example: if the well is shut in because it was in poor communication with the reservoir, it will not provide a representative pressure measurement for this pool. The practice of utilizing opportunities to survey at reduced costs is encouraged, where adequate areal coverage is not sacrificed and some producing wells are included in the survey.

4.5.9 Observation Wells

Shut-in wells can be candidates for testing and reduce the cost of a required pressure survey, **provided** they are representative of the producing portion of the pool, as described above. It is unacceptable to use a well that was shut in because of poor communication with the pool. An annual survey utilizing shut-in well(s) should include a combination of producing wells, and provide adequate areal coverage of the pool. A good example of utilizing a shut-in well for observation purposes, is to monitor the pressure of an aquifer where water disposal could result in over-pressuring.

Plans to retain a shut-in well as an observation well, requires submission of EUB form S-4 to the EUB's Well Records Section. All requests for "observation well" status are forwarded to the Well Test Section for approval. Applicants will be required to provide information regarding the type and need of the data being gathered. This information will be considered in conjunction with requirements for that well/pool, data reported to the EUB, and long term implications regarding the EUB's requirements for the administration of inactive wells.

Once an observation well is approved, the EUB will conduct random audits to monitor the ongoing use of the well for observation purposes. If the intent of the observation well was to monitor pressure data, the pool will be added to the annual survey schedule, with full compliance administration. The pool will remain on the survey schedule until the licensee requests exemption and the well reverts back to the inactive well administration system.

4.5.10 Pools on Good Production Practice

Do not assume that pools on Good Production Practice (GPP) are exempt from pressure survey requirements. That assumption may have been fairly safe in the past, when GPP was only granted after years of production and pressure data very clearly indicated a well established trend. Today, GPP is granted very early in the life of many pools, and ongoing pressure data is critical to monitor the effects of higher withdrawal rates during development of the pool.

4.6 Modifying the Basic Requirements

Pressure survey requirements are set early in the life of a new pool, when the well(s) are most productive. The EUB program routinely waives, without application, pools that do not meet the criteria defined in section 4.5 of this Guide, unless special needs have been defined. For example: pools with enhanced recovery, off-target wells, special pressure clauses in GPP and CCP approvals; will be forced onto the survey schedules. These pools will remain on the survey schedule until such time as the EUB and the licensee(s) agrees that pressure data is no longer required.

However, once a pool is fully developed and the questions of pool delineation, reserves, recovery mechanism, etc. have been answered, survey requirements may be reduced. When a licensee believes that a pool should qualify for relaxation or exemption, application should be made to the EUB, including supporting data to substantiate the change. There is no fee for these applications.

Important Note: Licensees/Operators should be aware that reduction of survey requirements will NOT be considered for any pool unless all survey requirements have been fulfilled to date.

Other examples where a pool may qualify for waiver of survey requirements for a specific year would be if an extensive test was conducted in the previous year, if withdrawals have been negligible since the last survey, if the entire pool must be shut in to obtain quality data, etc.

Described below are situations where licensee/operators should consider requesting either relaxation or exemption from the basic requirements. This provides more flexibility for the licensee/operator to conduct the tests needed for their own use, but not at scheduled intervals tracked by the EUB. While each situation must be considered on its own merits, some general guidelines are provided to streamline the process, and to show how requests for relief may be approved. All requests should be directed to the EUB's Well Test Section of Systems and Resource Information at the EUB Calgary Office.

THE NEED FOR THE DATA SHOULD ALWAYS BE THE MAIN REASON FOR TESTING.

Please note that applications for waiver or exemption of the survey requirements received after 1 November of the current year may result in two surveys being required in the following year, if the application is denied.

4.6.1 Declining Productivity

Due to the need to define the pools requiring surveys very early in the year, it is necessary to determine productivity based on the previous year's production. If a well/pool has declined to below the minimum productivity rates indicated in section 4.5.1, please contact EUB Well Test staff as indicated above. To qualify for this reduction, all wells in the pool must have limited production. Exemption will not be granted for individual wells or portions of pools.

4.6.2 Heavy Oil Pools

The pressure response of a reservoir fluid is a function of the fluid's viscosity. The heavier the density of the crude oil, at reservoir conditions, the more viscous the fluid. Oil densities over 900 kg/m^3 are considered heavy enough to merit consideration for relief from the annual pressure survey testing requirements. Pools with an oil density over 925 kg/m^3 will only be added to the annual survey schedule if special circumstances exist (e.g., waterflood). Between 900 and 925 kg/m^3, the licensee/operator is expected to provide supporting evidence in a request for relief from pressure testing. This evidence should include field data and analyses, which show that stabilized reservoir pressures cannot be obtained using conventional survey methods.

Relief may range from reduced pool pressure survey requirements to complete exemption. In general, the initial pressure requirement would still apply, and is probably needed to make a case for relief. Relief will not be granted on the basis of an oil density below 900 kg/m^3.

There are no survey requirements for wells within designated oil sands areas, although any surveys conducted must be submitted to the EUB.

4.6.3 Low Permeability Pools

The time required for pressure build-up is inversely proportionate to permeability. In general, whenever a reasonable estimate of the stabilized reservoir pressure can be obtained within a 14-day shut-in period (using build-up or static pressure measurements), the basic pressure requirements apply. A measured or extrapolated pressure that is at least 95 per cent of the fully built-up pressure is considered adequate for most reservoir management/ development applications.

Where it takes more than 28 days to estimate a stabilized pressure, exemption from pool pressure surveys may be granted upon application. Between 15 and 28 days, relaxation may be granted upon application, depending upon the need for the data. For example, where a 21-day shut-in period is needed to gather sufficient data for a transient pressure test, the number of pressure surveys may be halved. These applications require supporting evidence including interpretation of previous pressure buildup tests, establishing the reservoir parameters pertinent to the application. For further information on time to stabilization see EUB Guide 3 *"Gas Well Testing Theory and Practice"*.

4.6.4 Small Reserve Pools

The economic burden of testing increases with smaller pools. Therefore, the pool pressure survey requirement will be routinely waived for oil pools with established recoverable reserves less than 15 e^3m^3 (94 347 bbl), and for gas pools with recoverable reserves less than 30 e^6m^3 (1.06 bcf). The reserves, in this case, are the EUB's established (recoverable) reserves as published annually. The initial pressure requirements remain in effect. However, where a licensee/operator can show, from a reliable production decline analysis, that a pool's recoverable reserves are small, as defined above, the pool pressure may be waived.

Most of these small reserve pools are single well pools. With the 25 per cent annual pool pressure survey rule, once a subsequent pressure has been submitted, further testing would not normally be required for another four years. By this time, the pool's recoverable reserves and boundaries should be defined with some confidence.

4.6.5 Reserves Review

When a licensee believes that a pool on the survey schedule should qualify for exemption under the recoverable reserves or stage of depletion criterion, application should be made to the EUB. These applications must include data to substantiate a change to the recoverable reserves currently recognized by the EUB, and will result in a change to the recoverable reserves booked by the EUB.

4.6.6 Primary Pools with Advanced Depletion

When a pool has produced 50 per cent of its recoverable reserves, it will be exempted from the pool pressure survey requirement. The EUB will endeavour to identify these pools, and not include them on the annual survey schedule, as addressed in section 4.5, unless special circumstances have been identified. However, this does not preclude the licensee/operator's prerogative of requesting relief at any time. These applications should contain the licensee/operator's estimate of recoverable reserves and depletion, and a

statement of future plans for the pool. The EUB will check its reserve estimate and the pool's pressure history; if any concerns arise the licensee/operator will be advised.

4.6.7 Pools with Enhanced Recovery

Generally, survey requirements in a pool with enhanced recovery may exceed the minimum requirements, in order to monitor the effects of injection. In addition, survey coverage in patterned floods generally requires a representative pressure test on a producing well in each pattern. These special requirements, along with time lines for submission of test results, and the reasons, will be outlined in EUB correspondence. Time lines may be specified for the submission of test results, to coincide with operational meetings with EUB staff. Survey requirements/compliance should be addressed at these meetings.

Sufficient pressure data should be taken to determine the pressure for both recovery mechanisms, in pools where both primary and enhanced recovery schemes are operating. When enhanced recovery has been deemed "not feasible" for the primary area, a relaxation or an exemption from testing in the primary area, may be requested.

Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected. Shut-in wells, within the producing area of a pool, may be good candidates for pressure observation, providing they are in good communication with the productive area of the pool. However, if a well is suspended because it is in a very tight portion of the reservoir, or an area that has watered out (the flood front has passed), it would likely not provide any useful data in determining the pressures and trends of the producing area. In general, pressures from shut-in wells and new wells (initial pressures), should be used together with pressures from producing wells to satisfy a pool's pressure survey requirement.

The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone, or assessing whether producing wells are in compliance with a minimum operating pressure (MOP). In unique circumstances, where it has been shown by previously correlated data that a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).

When a horizontally flooded enhanced recovery scheme, with an MOP, is in its latter stages of depletion, the MOP may be reduced to the bubble point pressure, or some other applicable pressure. Requests to amend the operating pressure should be directed to the Reservoir Applications Group, and contain

discussions on the suitability of the existing MOP and the proposed operating pressure along with future plans for the scheme.

Static gradient tests with short shut-ins (less than 14 days and below the stabilized conditions) but with pressures above the MOP or other approved operating pressure may satisfy survey requirements. However, prior approval must be obtained from the Well Test Section and Reservoir Application Group, as per section 4.6 Modifying the Basic Requirements.

Relaxation of pressure testing requirements in pools with enhanced recovery, occur mainly by application. Any requests for relief from pressure testing in pools with enhanced recovery must still be submitted to the Well Test Section, to ensure a temporary change in status for compliance purposes.

4.6.8 Pools with Reduced Spacing

Where a pool is developed on reduced spacing, application of the basic pool pressure survey requirement may be excessive because it is based on the pool's productive well count. In general, where reduced spacing is needed to improve recovery, more pressure coverage may be needed during the early stages of a new pool, or step-out development stages of older pools. However, survey requirements for these pools can usually be determined by using standard spacing, as referenced in section 4.5 of this Guide. If deliverability is the main reason for reduced spacing requirements, additional pressure coverage is generally not required.

4.6.9 Pools with Active Waterdrives

Once sufficient pressure data has been gathered to establish that a pool has an active waterdrive, the survey requirements can usually be reduced. While further development may change the ability of the waterdrive to maintain the pool pressure, surveying 25 per cent of the wells is not necessary. Approval for reduction of requirements in these situations should be requested.

4.6.10 Pools with Commingled Production

In pools where approval has been granted to commingle production in a small number of wellbores in a pool, no change would be considered to the survey requirements, on this basis.

However, if most of the wellbores in the pool were commingling production, from different formations, the usefulness of the pressure data is greatly diminished. In these cases, the pressure measured in the wellbore reflects an unknown combination of pressures from the different formations, often complicated by the effects of crossflow. There may be special cases where pressure data is still required (enhanced recovery schemes), and specialized equipment would be required to obtain this information (e.g., sliding sleeves).

This requirement can also vary depending on the type of pool (oil or gas, or a combination of both).

Licensees/operators should be aware that the need for pressure data should be addressed in the application for approval to commingle production. The initial pressure or initial deliverability testing requirements may also be waived, upon request, where commingling is granted prior to completion of the well.

4.6.11 Recommended Practices for Pressure Survey Design

Some additional practices that should be considered when designing (coordinating) a pool pressure survey are listed below. However, it is always important to keep in mind what this pressure data will be used for; what we are trying to find out about this pool.

- Whenever possible, pressure surveys should be scheduled to coincide with planned well down time.

- It is important to return the well as close to producing conditions as possible, or wait until the transient introduced has dissipated; or, when fluid is used to "kill" a well in preparation for testing, that fluid should be swabbed back prior to commencement of the test.

- In pools where both primary and enhanced recovery schemes are operating, sufficient pressure data should be taken to determine the pressure for both recovery mechanisms, until enhanced recovery has been deemed "not feasible" for the primary area.

- The use of injection wells as candidates for pressure testing usually results in a higher pressure and would not be acceptable for determining the pressure in the producing zone or assessing whether producing wells are in compliance with Minimum Operating Pressures (MOP). However, if pressure transient analysis or previously correlated data, indicates a pressure from an injector is representative of the producing area of the pool, this may be deemed acceptable. This will usually occur when injection fluid is taken on vacuum (e.g., reef type pools).

- Survey coverage early in the life of an enhanced recovery scheme with a patterned flood generally requires a representative pressure test on a producing well in each pattern. Later in the life of the scheme, selection should be based on performance and previous pressure information.

- Pressure sinks or highs in pressure maintenance schemes should be monitored each year until the problem is corrected.

- Shut-in wells within the producing area of a pool, may be good candidates for pressure observation providing they are in good

communication with the productive area of the pool. See section 4.5.9 for more information.

- An initial pressure is often relatively simple and inexpensive to obtain; therefore, it should be taken for all wells, including infill wells, whenever practical.

- Pressure build-up data should be taken as early as possible in the producing life of a well. However, it is important to ensure that sufficient drawdown has occurred to establish an effective (practical) time to stabilization, as detailed in section 5.1.

4.7 Drill Stem Tests

Requirement:

There are no regulations governing the conducting of drill stem tests; only the requirement to submit all drill stem tests conducted, in the DST.PAS electronic format.

All DSTs conducted, including misruns, must be submitted in the DST.PAS format (as defined in Guide 52). This includes reporting the closed chamber portion of a test. To submit a DST to fulfil the initial pressure survey requirement, the [PRPS] (well test purpose) flag in the TEST DATA section must be set to "Y"(es).

The type of DST to run is left up to the licensee/operator to gather the information they need. The EUB requires that all regulations regarding safety and environmental issues be followed, or any other operational concerns addressed.

The EUB administers the DSTs that have been conducted, according to the information on the EUB Form WR-2. The licensee has 30 days from the finished drilling date of the well, to submit these reports. Failure to do so will result in compliance issues as defined in section 6.0 of this Guide.

4.8 Gas and Fluid Analysis

Requirement:

All gas and fluid analysis on samples gathered at a well, which are representative of the formation (not mixed stream), must be submitted electronically in the appropriate PAS file. If multiple samples/analysis done – all must be submitted.

Further, all gas and/or fluid samples analyzed in conjunction with the following tests must be submitted:

- DSTs conducted on wells outside of existing pools, as per the current EUB G-Order
  - fluid analysis is required if fluid is recovered during the test
  - gas analysis is required if gas to surface during the test

- All deliverability tests require gas analysis for the fluid analysis correlation and must therefore be submitted:
  - with AOF on all wells drilled outside of existing pools, as per the current EUB G-Order

- Initial Pressure Tests conducted on wells outside of existing pools, as per the current EUB G-Order:
  - gas analysis is required for oil and gas wells
  - fluid analysis is required for oil wells, and gas wells producing liquids OR, provide details regarding the source of analysis used in the correlation.

- Acoustic Well Sounder Tests require analysis information when calculating acoustic pressures:
  - gas analysis is required for all acoustic tests,
  - fluid analysis is required when fluids are present in the wellbore OR, provide details regarding the source of analysis used in the correlation.

- Pressure Transient Analysis requires gas and fluid properties for calculations. OR, provide details regarding the source of analysis used in the correlation.

4.9 Submission Requirements

Requirement:

Licensees/Operators are required to submit to the EUB, in the appropriate electronic .PAS format, all pressure and deliverability tests, DSTs, gas and fluid analysis conducted, from samples collected at the wellhead, including those not required by this guide, as per section 11.120 of the Oil and Gas Conservation Regulations and EUB Guide 52.

This includes tests conducted within designated oil sands areas. Only those tests conducted under controlled conditions need be filed, including; drawdown tests, interference tests, two-rate tests, segregation tests, reservoir limits tests, injection or fall-off tests, and so on. A casual reading of a wellhead pressure with a portable dial gauge or a pumping fluid level need not be reported. Likewise, if you have conducted a test that failed and has no useful

information, it need not be submitted, with the exception of DSTs, where all tests must be submitted including misruns.

Where the EUB determines that a test has been conducted and not submitted, the matter becomes a non-compliance issue, subject to the measures detailed in section 6 of this Guide.

If an application has been submitted, referencing a pressure that has not been submitted, the licensee will receive a notice letter starting the compliance process. The application will be considered deficient, and processing will be delayed until all data is available.

If test data pertinent to a land sale has not been submitted:

- if the sale is pending, sale of the property in question may be deferred until all data is available, or
- if the sale has occurred, the results may be reversed and the property re-issued for sale when all data is available.

For gas, oil, or water analysis, only those samples gathered from a well need be submitted.

4.9.1 Timing of Submissions

Requirement:

- **All pressure and deliverability tests must be submitted within 90 days of completing the field work.**
- **All DSTs must be submitted within 30 days of the finished drilling date.**
- **All gas and fluid analysis must be submitted within 45 days of completing the test.**

This time is provided for the licensee/operator to complete analysis and review the results. Compliance follow-up on initial pressure and deliverability tests will begin after production has been reported in three consecutive calendar months. Although the mechanism for EUB to administer initial tests is the first three consecutive months of production reported, the 90-day rule is still in effect. If documentation is provided that indicates a well was tested and the data is not in the EUB records, you will be required to submit that test even though the well has not commenced production.

Any annual tests not received by 31 March of the following year, will be deemed in non-compliance and have consequences assessed. This ensures that tests conducted in November or December have the full 3 months to compile and submit the test results.

Compliance follow-up on DSTs will commence 30 days from the finished drilling date for each individual well.

4.9.2 Reporting Formats

All reports must be submitted electronically in the current version of the .PAS format as defined in Guide 52. The most current version is always available on the EUB website at

http://www.eub.gov.ab.ca/bbs/dds/welltest/welltest.htm

The electronic report must include a TIFF file as indicated in Guide 52, with any charts and graphs, dialogue, explanations, and any parameters used in the analysis and results that have not been included in the PAS file.

Test/survey reports should contain a complete record of any event that may have affected the quality or interpretation of the data. The objective is to provide sufficient information for anyone using the data to be able to assess its reliability. All test results should be compared with the results of previous tests, if applicable, and both should be reported. Where anomalous data is encountered, explanations should be provided, or the well should be re-tested.

When tests have been run only for the licensee's use, and are not intended to fulfil survey requirements, indicating "N"(o) in [PRSP] flag in TEST DATA section of the PAS file, will ensure that quality requirements are not applied, and the licensee/operator not requested to provide further validation and analysis of data.

Although there are no basic requirements for wells in designated oil sands areas, all tests conducted must still be submitted to the EUB. With the concerns regarding the possible effects of gas production on underlying bitumen reserves, pressure information has become more critical than ever in these areas, including the gas wells overlying the bitumen deposits.

5 Acceptable Test Standards

The manner in which tests/surveys are conducted and reported is always critical to the value of the data obtained. This section defines the quality standards required for tests to fulfil survey requirements.

The "Acceptable Survey Standards" for required tests have been translated into edits which are defined in EUB Guide 52 – Electronic Capture of Well Test Data". Some edits are critical, which will result in the file being rejected. Other edits that require some interpretation have been identified as non-critical and will not cause the file to be rejected. These edits will be administered by an audit process. Tests not meant to fulfil any requirement can be indicated in the Test Data Section of the appropriate PAS file, and the "acceptable survey" criterion will not be applied. This can be indicated by setting the [PRPS] (test purpose flag) = "N"(o).

All tests conducted must still be submitted to the EUB, as per section 11.120 of the Oil and Gas Conservation Regulations, as defined in section 2.0 of this Guide. All submissions must be made electronically as defined in Guide 52.

5.1 Obtaining a Stabilized Reservoir Pressure

A major problem with pressure data is determining whether or not the pressure is representative of a stabilized reservoir pressure. If a transient pressure test is being submitted to fulfil requirements, the PAS file must either include analysis, or the raw data must reflect a stabilized reservoir pressure. For most purposes, a "stabilized reservoir pressure" is defined as a pressure that does not build over two kPa/hour during a six-hour period.

The following four methods are acceptable for obtaining pressures that are representative of stabilized shut-in reservoir pressures, in order of preference. Further details of these methods are included below:

(1) Measure sufficient transient data to reliably extrapolate to a stabilized reservoir pressure (P_R). See EUB Guide 3 "*Gas Well Testing Theory and Practice*" for more information. Transient tests must be submitted with analysis, or they will be rejected as deficient (note: for a flow and build-up test, the shut in should be four times the flow period).

(2) Measure pressure build-up until the change in pressure is less than or equal to two kPa/hour, over a six-hour period.

(3) Measure a static pressure after a shut-in sufficient to reach a stabilized pressure, as determined from previous transient data on this well (if previous transient data indicates a shut-in in excess of 14 days is required to reach a stabilized pressure, the EUB expects the licensee/operator to use the appropriate shut-in, but relief from testing requirements should be considered as discussed in section 4.6.3).

(4) Measure a static pressure after a shut-in time of at least 14 days, where no transient data is available.

5.1.1 Transient Pressure Tests with Analysis

The first method involves gathering and extrapolating transient data. This is considered the most efficient method of determining a stabilized shut-in reservoir pressure. Transient data can be costly to obtain; but it has the added advantage of providing estimates of reservoir rock properties and completion effectiveness.

With electronic submission, a critical edit will check for an average reservoir pressure (P_R). A correction to average reservoir pressure is required in a producing pool P* or the False pressure from the Horner Plot is not representative of the average reservoir pressure and will be corrected using the MBH techniques as described in EUB Guide 3.

5.1.2 Transient Pressure Tests Without Analysis

The second method involves conducting a transient test (extended measurement of buildup) that has reached pressure stabilization. The acceptable pressure change rate indicating stability would be less than 2 kPa per hour. However this rate of change may not indicate stabilization in systems with dual porosity/permeability, fractures, stratified layers, phase separation in the wellbore, etc. If these circumstances exist, 2kPa per hour should not be used.

The following critical edits determine if a stabilized reservoir pressure has been reached. Tests submitted without analysis that do not meet this criteria will be rejected:

- Get the values reported as:
  - RESULTS SUMMARY [PMPP] (representative bottomhole pressure at MPP) for AWS tests, or
  - RESULTS SUMMARY [PRGA] (last measured or representative pressure at stop depth) for TRG tests
- Match these values to the acoustic data table, or the gauge 1 (source gauge) data table.
- The difference in pressure over the six hours prior to this value must be equal to or less than 12 kPa (2 kPa per hour as defined in section 5.1 of Guide 40).

- If a pressure reading cannot be found at the six-hour interval prior to [PMPP] or [PRGA], the edit will look for the next previous reading and determine if the 2kPa/hr limit has been met.

IMPORTANT: **If this program cannot match the value reported in RESULTS SUMMARY [PMPP] or [PRGA] in the raw data table, the file will be rejected.**

5.1.3 Static Pressure Tests

The final two methods involve static pressure measurements, which can be the most cost-effective method of survey; but they are of little value if the shut-in period is too short, and the well build-up character is unknown.

For the third method, the time required to obtain a stabilized reservoir pressure must be determined from previous transient data, conducted on the same well. The full time to reach theoretic stabilization calculated as part of the transient analysis is not required. For most reservoir management/ development applications an effective time to stabilization, that is at least 95 per cent of the true (fully built up) stabilized pressure, is satisfactory. The effective time to stabilization can be determined by taking 95 per cent of the extrapolated pressure and determining the time it took to reach that point. This time may change during the life of the well and may need to be re-established, depending upon depletion, re-completions, well treatments, etc. An initial pressure transient test does not usually provide a basis for a establishing buildup time to a stable pressure after the well has produced for several months. The initial test time is very short (small radius of investigation) in relation to the long production time on subsequent tests after the well has produced commercially. Consequently, the time to reach a stable pressure can be much greater than observed on an initial test.

In some cases, the shut-in time needed to reach stabilization can be estimated from offset wells and applied to the current test as a guide to determine a necessary shut-in time or when to terminate the test. However, this is only applicable where reservoir characteristics are very similar, and the expected time to stabilization would be the same. In general, it would not be acceptable to use only the shut-in time from an offset well to determine the length of time to conduct a static pressure test.

The fourth method also involves a static measurement but in this case there is no supporting analysis. Therefore, a minimum shut-in time of 14 days was selected because it should provide adequate pressure build-up for most reservoirs. An exception to this would be in enhanced recovery schemes with a Minimum Operating Pressure (MOP). In these instances, a static test may be accepted, if it indicated the well/scheme was operating above MOP, regardless of the length of shut-in time. However, this method must be approved by EUB staff, and these pressures should not be used for reservoir calculations or

modeling, as they are not representative of the reservoir pressure (this is an example of designing a test for a specific purpose).

When conducting an initial static pressure, remember that drilling, completion, and cleanup operations create some drawdown, or may be overbalanced. However, since production from the well has been minimal, a 14-day shut-in is probably not required for an initial static pressure survey. Please indicate that the pressure is stable on the report in the RESULTS-SUMMARY section, under [PRGC] (Comment on Pressure) element. Also, an initial static gradient with a longer stop at bottom (minimum two hours) would be acceptable, providing it indicates pressure stabilization.

5.1.3.1 Surface Indication of Static Pressure

In certain circumstances, a stabilized pressure can also be obtained by monitoring the surface pressure until it stabilizes then measures or calculates the down-hole pressure. See section 5.3 of this Guide for further information.

5.2 Acoustic Testing

The most accurate way to measure subsurface pressure is direct measurement, by subsurface gauge. However, this method is very costly where pump and rods have been installed. In some cases it is acceptable to determine the bottomhole pressure indirectly using an acoustic method, providing the conditions detailed in this section of this Guide are met.

Currently, about one quarter of all pressure surveys on oil wells are acoustic surveys. Unfortunately, the quality of acoustic surveys has varied considerably in the past, which has given them a poor reputation, and has limited their use in reservoir studies. EUB Guide 5 "*Calculating Subsurface Pressure via Fluid Level Recorders*", states "Experience has shown that the accuracy of subsurface pressures obtained from fluid-level measurements has, at times, proved questionable. Although the producing characteristics of many wells preclude great accuracy, the lack of accuracy can be attributed in may cases to improper data-gathering procedures, interpretation, and pressure calculation techniques".

There are practical ways to address these problems. First, the acoustic method should not be used where it is reasonable to run bottomhole gauges. Acoustics should be used for wells or circumstances where there is the best chance of obtaining meaningful pressure data. Second, the data gathering and field measurement procedures in Guide 5 should be followed at all times. Finally every effort should be made to improve the accuracy of the calculations of subsurface pressures.

5.2.1 Verification of Acoustic Methods

Acoustic pressure surveys may be accepted if the following conditions are met:

- the pressure being taken is not an initial pressure,
- the fluid properties used for the calculation must be accurate and appropriately derived or confirmed by comparison to static gradient tests or PVT study data,
- the well does not produce water, OR
- the well produces water, but there is a 15 per cent or less difference between bottomhole pressures:

(1) calculated by the acoustic method, assuming the influxed liquid column is all oil, compared to all water:

$$\frac{(\text{Initial Fluid Level} - \text{Final Fluid Level}) * (\text{Water Gradient} - \text{Reservoir Gradient})}{\text{Extrapolated Pressure at MPP}}$$

OR

(2) calculated by the acoustic method, and measured simultaneously using a bottomhole gauge.

When the acoustic method has been verified by method (1) or (2) above, it may be accepted for subsequent pressures in the well providing the same acoustic testing procedures are repeated. Method (1) is an effort to minimize the margin for error in situations where the well produces water. When verification is by (1), the submission should contain some discussion regarding the changing water influx. Guide 5 addresses the fact that producing watercuts are seldom representative of water within the fluid column in the annulus, and should not be used when making calculations, as the watercut in the annular column will change over time. There are now models available in industry that take this factor into consideration. Another factor to consider is gas influx, which lowers the liquid level, thus driving water back into the formation.

When verification is by method (2), the submission should compare liquid levels between the acoustic and gauge tests, oil/water contacts at the end of the test, gradients used and their origin, and procedures used to control conditions to ensure consistent data for future tests. Although at first a gauge/acoustic validation may not appear to be within acceptable limits, once the above items have been addressed and final wellbore liquid content determined, a process can often be developed to calculate representative pressures for future use in that well. However, if subsequent tests are submitted where data does not appear reasonable, the verification will be considered invalid.

The verification results from wells in one pool cannot be used for wells in other pools; however, these results may be applied to other wells in the same pool, that have similar reservoir characteristics. The acoustic method must be verified in a representative sample of wells before it will be routinely accepted in large multi-well pools. Again, it is important to follow the practices established in the verification process in future acoustic testing.

When conducting an acoustic test on a suspended well that experienced high watercut during production, it is important to determine if any water still exists in the wellbore. The length of time the well has been shut in and the reservoir characteristics can affect this determination. If the well is to remain suspended, but is a good representative pressure source, it may be advisable to remove the pump and rods and use the well for observation purposes, with subsurface gauge surveys.

Acoustic pressures should always be compared with the last pressure or pressure trend. Where anomalous results are indicated, the acoustic pressure may not be accepted, and further verification of the acoustic method may be required.

5.2.2 Acoustic Test Design

When designing and running an acoustic survey:

- A build-up survey is preferred over a static survey because it monitors the movement of the gas-liquid interface and wellhead pressures, and provides a better understanding of reservoir and wellbore dynamics. A build-up survey also provides additional information such as permeability and skin.

- Before conducting any acoustic survey on a producing well, the pumping fluid level must be determined. This practice significantly improves the chance of obtaining acceptable acoustic data. If the well is suspended or has been shut in for sometime this may not be possible.

- The presence or absence of foam should be established via a foam depression test.

- A sensible shot schedule should be used for build-up surveys. Typically a minimum of 20 to 30 points are required. They should be spaced logarithmically.

- When the pumping fluid level is high, depressing the gas-liquid interface prior to shut-in may be considered. In high GOR wells this can be done using the well's back pressure. In low GOR wells, forced fluid depression can be achieved by pumping nitrogen downhole.

- When an acoustic survey is to be conducted on a static well, more than one shot should be taken especially when single-channel equipment is used.

- The input data for the bottomhole calculation (fluid properties, average joint length, etc.) must be current and accurate.

- The practices in EUB Guide 5 should be followed.

It is a much more complicated engineering problem to calculate acoustic bottomhole pressures than to measure them with downhole recorders. It is important to have representative fluid compositions and final production rates. Also, the wellbore schematic, tubing tally, and directional survey data should be up-to-date. Finally, the casing pressures and fluid levels should be measured by experienced field personnel, using accurately calibrated and well-maintained equipment. This is just as important as ensuring the integrity of subsurface gauges.

In extenuating circumstances, where a pressure minimum is involved, the EUB may consider a pressure that would be above MOP if the calculation assumed the wellbore liquid was all oil.

However, prior approval would be required for use of this method, and these pressures should not be included in determining an average scheme pressure.

5.3 Surface Pressure Tests

The method of monitoring surface pressures with memory digital surface recorders has been used by some companies recently, as a means of determining reservoir pressure stabilization. This method assumes that stabilization of pressure at surface is indicative of stabilization downhole. The bottomhole reservoir pressure is then determined using acoustic fluid level data obtained once stabilization at surface has occurred. As in section 5.2.2, the integrity of the equipment used to measure surface pressure is paramount to the success of your test.

This method of monitoring reservoir pressure stabilization is acceptable in many cases, providing:

- it is not an initial pressure survey,
- the minimum of an initial and final fluid level shot are conducted and reported, including all parameters required for an acoustic survey, and
- the test meets all criteria defined for an acoustic test in section 5.2.

5.4 Permanent Downhole Gauges

In instances where it is necessary to monitor the pressure in a particular well on a frequent basis, it may be desirable to install a permanent type of gauge downhole. There are a number of these gauges on the market, but problems are often experienced if a maintenance program is not followed. Further information on maintenance of these gauges can be obtained from their respective manufacturers. Tests submitted from this method must meet all standards of reasonableness. See section 8.0 for calibration requirements of these gauges.

Pressure data obtained from these gauges must be reported in the appropriate electronic format defined in Guide 52.

5.5 Drill Stem Tests (DSTs)

As in the past, DSTs must be conducted adhering to all environmental and safety requirements. All DSTs conducted are required to be submitted within 30 days of the finished drilling date of the well, as per section 11.100 of the Oil and Gas Conservation Regulations. This requirement includes misrun tests, which often provide some useable information.

The responsibility for administering DSTs at the EUB has switched from the Well Records Section to the Well Test Section of the Systems and Resource Information Group, with the implementation of electronic data capture. All tests must be submitted in the DST.PAS electronic format as detailed in EUB Guide 52. This format also includes all closed chamber data that may have been collected.

The EUB will administer compliance for submission of DSTs based on the information reported on EUB form WR-2 with applicable details also recorded on the tour report forms. See section 6 for further information on compliance administration.

5.5.1 DSTs Submitted as Initial Pressures

All of the following conditions should be met if a DST pressure is used to satisfy the initial pressure requirement:

- The test must be mechanically sound (no skidding, plugging, or loss of packer seat).

- The extrapolated pressures (P*) from any two shut-in periods should be within one per cent of each other, and clearly different from the hydrostatic pressure.

- The last measured pressure and the extrapolated pressure (P*) from the final shut-in period **must** be within five per cent of each other.

- If the DST is being submitted to fulfil a pressure survey requirement, the [PRPS] flag in TEST DATA section must indicate "Y"(es). If you decide that you want a DST to fulfill your initial pressure survey requirement, but you have already submitted the file with [PRPS] flag = "N", you can resubmit the same DST.PAS file by just changing the [PRPS] flag to "Y". It will not be rejected as a duplicate, but more edits will be activated by this flag.

5.6 Wireline Formation Tests (WFTs)

The following provides some recommended practices that must be adhered to when using an WFT to obtain an initial pressure:

- The data must be interpreted by a qualified individual(s) using industry- accepted techniques. Special considerations exist with WFT interpretations and interpretation techniques applicable to the measured data. General Horner/Derivative techniques can be used, but the unique near-wellbore nature of these tests tends to invalidate basic Horner flow criteria.

- An on-record master calibration certificate for each transducer used must be available. Service companies must have their master calibration device compared to EUB standards annually, as detailed in section 8 of this Guide.

- More than one single test within a particular reservoir must be taken. The wide variance on the test quality and pressure response between individual tests, makes it critical to have at least two good quality pressures which fall within the repeatability specification of the tool.

- Reports for WFTs intended to fulfil a pressure requirement must be submitted in the electronic DST.PAS format, as per Guide 52.

The near well-bore nature of this kind of test needs special consideration in two main areas:

Depletion: Since the pressure distribution within a single zone very often differs significantly from test to test, due to preferential depletion in a developed reservoir, it is not practical to assign a single pressure to such a zone. While it is accepted that the requirements pertain to new pools where this should not be seen, more variation is observed across a single zone than is historically seen from a conventional single test that straddles the entire zone, which provides a single average pressure value. A single zone with the presence of gas, oil, and water will yield a pressure profile that does not lend itself to an easy mathematical function which describes a single, average pressure. A general technique to convert several pressures to a single value needs to be defined.

Supercharging: The near wellbore nature of these tests often yields pressures which are obviously too high when compared to other nearby pressures obtained through conventional means. The discerning factor is near wellbore permeability. Experience has shown that near the one millidarcy permeability level, as measured by WFT/MDT type tools, measured pressures are very likely to be affected by the excess pressure of mud filtrate invasion that has not had sufficient time to re-stabilize because of low permeability. Pressure tests with this problem will appear and interpret completely normal. However, due to the very shallow depth of investigation and the excess pressure from mud filtrate invasion, the pressure will not be representative of the formation, but some value higher than formation pressure.

Proper interpretive techniques are available to recognize but not correct for pressures that appear too high. This further emphasizes the need for experienced personnel.

5.7 Surface Acquired Fall-Off Tests (Data Frac, Mini Frac, Hydraulic Fracture)

In low permeability reservoirs, DST and/or a pre-stimulation test may not provide adequate inflow and/or pressure buildup to determine a reasonable initial reservoir pressure. Fracture fall-off pressure data may provide an alternative method of determining an acceptable reservoir pressure. A dead-leg (full column of fluid) is often used to monitor frac fall-off data and using this method of measurement can provide reasonably accurate and confident bottomhole pressure determination. However, this method is acceptable only when conventional testing in not possible, and extreme care is taken to ensure representative results. Whenever possible, a bottomhole pressure should be obtained by some other method to validate the results.

An operator must verify and substantiate that the bottomhole pressures have been properly calculated and pressures are representative of reasonable values. If a pressure can be proven to be representative, the EUB may accept the pressure to fulfil survey requirements. These tests are to be reported electronically in the AWS.PAS file format.

The following conditions must be met if surface data from a frac fall-off are used to determine an acceptable reservoir pressure:

- The column of fluid used is "dead fluid" and has no gas present.
- The density of the frac fluid being used is known and samples are obtained and analyzed.
- The well does not go on vacuum (hydrostatic pressure is less than reservoir pressure).
- Fluid levels may be determined but further acoustic validation is required.
- The surface gauges used must have reasonable resolution and accuracy and have been properly calibrated.
- The wellbore has less than 10 per cent of its volume saturated with a proppant even with properly calculated slurry densities; corrections can be erroneous (unless a dead-leg is used).
- The final fall-off pressure and the extrapolated pressures are within five per cent of each other. **The analytical method for extrapolations and comparison must be validated. If a flow regime can be identified the appropriate analytical method of analysis can then be applied.**
- The operator must verify and substantiate that the bottomhole pressures have been properly calculated and are representative of reasonable values. The submission must include a discussion of the methods used and the relevance of the pressure measurement.

Note: **Fall-off tests from large hydraulic fracture treatments may require an unreasonable long shut-in time to obtain sufficient information to determine a representative pressure.**

6 Compliance to the Minimum Requirements

The EUB believes that compliance is the responsibility of the operators. It is up to each individual licensee/operator to understand their requirements and develop an infrastructure to ensure compliance. Compliance with the minimum requirements is considered a must, not only for the effective and prudent management of oil and gas reservoirs, but also to ensure fairness and consistency among a diverse operating industry.

Non-compliance with the requirements regarding flaring and emissions and with the minimum well testing and submission requirements will result in consequences that escalate in severity, consistent with the EUB's Enforcement Policy, and with the degree to which compliance was not met. **Every** instance of non-compliance in well testing will be pursued by the EUB, and will result in consequences imposed on those who do not do their part to meet these requirements. All enforcement actions for non-compliance shall be timely, effective, and appropriate to the severity of the issue. Repeated or continued non-compliance shall be dealt with through escalating enforcement consequences. These consequences and respective time lines are detailed in the following tables.

The minimum requirements and the guidelines for modifying the requirements give reasonable test data coverage without undue burden. However, the EUB is aware that there may be extenuating circumstances that are not recognized by these requirements or this Guide. The licensee/operator is always welcome to address such issues with the EUB, and request recognition as a special case, providing these issues are addressed in a timely manner and not after the assessment of consequences (see section 6.3). The EUB is committed to working with industry to ensure the enforcement actions set out within this Guide are appropriate and consistent with comparable situations of similar severity.

The compliance model detailed in section 6.1, for initial deliverability testing of gas wells and initial pressure testing of oil and gas well, became effective on 1 July 1997. Any well drilled after that date that is not tested in accordance with the requirements will be subject to the consequences described for non-compliance.

The annual survey requirements for oil and gas pools became effective in the 1997 survey year. Any annual survey requirement not fulfilled by 1 April of the following year will be subject to the consequences as detailed in section 6.2. Past compliance performance will not initially be an issue. However, where an infraction escalates to a higher level, past performance will be part of the EUB's decision respecting a licensee/operator.

The requirement for all DSTs conducted has been in effect for sometime. Any DSTs not submitted within the 30-day timeframe will be subject to the consequences as detailed in the tables in section 6.2 of this Guide. The requirement for submitting gas and fluid analysis on samples taken at the well (representative of the formation) has also been in effect for some time. The table in section 6.2 also addresses compliance for submission of gas and fluid analysis.

6.1 Compliance Tools and Administration

To facilitate compliance administration, the EUB has posted the following files on our EUB website. These files are updated every 2 weeks and include the following information:

(1) A list of all outstanding wells that require initial pressure/deliverability tests, including

- licensee,
- UWI,
- type of test required (Initial pressure test or deliverability test), and

(2) The annual survey schedules for oil and gas pools, including

- field and pool names and codes,
- coordinating operators,
- survey frequency,
- year survey due, and
- status (fulfilled, outstanding, etc.).

When dealing with non-compliance, it is the intent of EUB staff to achieve the goals listed below using fair, responsible, and balanced practices.

- Expectations and enforcement actions will be fully communicated to industry in advance with opportunity for stakeholder input.

- Industry licensee/operators will recognize the enforcement actions taken by the EUB and be motivated to prevent similar events from occurring again.

- The enforcement process used will achieve compliance and lasting improvement in industry operations without continuous EUB involvement.

- The enforcement action will be appropriate to the severity of the situation (firm and fair), and consistent with comparable situations. This process should ensure that operations are conducted in a responsible manner, resulting in a level playing field for all.

6.2 Calendar for Non-Compliance of Initial Pressure and Deliverability Testing, and Submission of DSTs and Gas and Fluid Analyses Requirements

The following table details the processes that have been adopted by the EUB for dealing with non-compliance issues in initial pressure and deliverability testing, and for submission of DSTs and gas and fluid analyses. Each letter/communication will include a warning of the consequences at the next level, should non-compliance continue.

FAILURE TO RESPOND TO THIS LETTER WILL RESULT IN FURTHER CONSEQUENCES AND LIABILITIES TO THE LICENSEE/OPERATOR.

EUB enforcement actions will commence on or about the first business day after the timeline identified below. Enforcement may be accelerated in the case of repeat offenses.

Calendar For Non-Compliance of Initial Pressure and Deliverability Testing, and Submission of DSTs and Gas and Fluid Analyses Requirements

Level:	**Responsibility of Well Licensee/Operator for Initial Pressure Survey**	**Responsibility of Well Licensee/Operator For Deliverability Test**	**Responsibility of Well Licensee/Operator for Submission of Drill Stem Tests**	**Responsibility of Well Licensee/Operator for Submission of Gas and Fluid Analysis**
	For new oil wells drilled outside of a pool as designated by EUB G-Order, and all new gas wells, reporting production in 3 calendar months, **where no initial pressure test has been received**;	For all new gas wells reporting production in 3 calendar months, **where no deliverability test has been received**;	For drill stem tests conducted, as per tour reports, **that have not been submitted within 30 days of the finished drilling date of the well;**	For gas and fluid analysis conducted, on samples gathered at a wellhead, **that were not submitted in conjunction with tests as required by section 3.5 of this Guide;**
NOTICE LETTER	**Day 1** - Letter to Licensee/Operator indicating 30 days to fulfil initial pressure testing requirement.	**Day 1** - Letter to Licensee/Operator indicating 30 days to fulfil deliverability test requirement	**Day 1** – Letter to Licensee/ Operator indicating 30 days to fulfil requirement for submission of DST.	**Day 1** – Letter to Licensee/ Operator indicating 30 days to fulfil requirement for submission of gas and/or fluid analysis.
LEVEL I	**Day 31** - Letter to Licensee/Operator's Production Manager, outlining: - $1000. Fee assessed against each well in non-compliance - 30 days to fulfil initial pressure survey requirement - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment.	**Day 31** – Letter to Licensee/Operator's Production Manager, outlining: - $1000. Fee assessed against each well in non-compliance - 30 days to fulfil deliverability survey requirement	**Day 31** – Letter to Licensee/ Operator's Production Manager, outlining: - $1000. Fee assessed against each well in non-compliance - 30 days to fulfil DST submission requirement	**Day 31** – Letter to Licensee/ Operator's Production Manager, outlining: - $1000. Fee assessed against each well in non-compliance - 30 days to fulfil gas and/or fluid analysis submission requirement

Calendar For Non-Compliance of Initial Pressure and Deliverability Testing, and Submission of DSTs and Gas and Fluid Analyses Requirements (continued)

LEVEL II	**Day 61** – Communication with Vice President of Operations of the licensee/operating company with letter confirming: - 7 days to address initial pressure requirement - Action plan to be submitted to the EUB - Operator/EUB meeting may be scheduled - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment. Existing approvals to increase production rates contingent upon pressure surveys to monitor depletion, will be reviewed and rescinded where applicable, unless conservation or equity factors prevail (application would be required to reinstate approval once pressure surveys accepted by the EUB). For repeat occurrences, a meeting with the VP will occur.	**Day 61** – Communication with Vice President of Operations of the licensee/operating company with letter confirming: - 7 days to address deliverability requirement - Action plan to be submitted to the EUB - Operator/EUB meeting maybe scheduled - For repeat occurrences, a meeting with the VP will occur.	**Day 61** – Communication with Vice President of Operations of the licensee/operating company with letter, confirming: - 7 days to address DST submission requirement - Action plan to be submitted to the EUB - Operator/EUB meeting maybe scheduled - For repeat occurrences, a meeting with VP will occur.	**Day 61** – Communication with Vice President of Operations of the licensee/operating company with letter, confirming: - 7 days to address gas and/or fluid analysis submission requirement - Action plan to be submitted to the EUB - Operator/EUB meeting maybe scheduled - For repeat occurrences, a meeting with VP will occur.

Calendar For Non-Compliance of Initial Pressure and Deliverability Testing, and Submission of DSTs and Gas and Fluid Analyses Requirements (continued)

LEVEL III	**Day 68** - Communication with CEO of licensee/ operating company with letter confirming: - Immediate suspension of operations at non-complying properties - 14 days to fulfil initial pressure survey requirement - Copy of letter to EUB Corporate Compliance Group (CCG) and Field Office for follow-up on suspension. CCG to include non-compliance information in Corporate Performance Record and database, enforcement may be accelerated in other areas. This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.	**Day 68** - Communication with CEO of licensee/ operating company with letter confirming: - Immediate suspension of operations at non-complying properties - 14 days to fulfil deliverability requirement - Copy of letter to EUB Corporate Compliance Group (CCG) and Field Office for follow-up on suspension. CCG to include non-compliance information in Corporate Performance Record and database, enforcement may be accelerated in other areas. This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.	**Day 68** – Communication with CEO of licensee/operating company, with letter confirming: - Immediate suspension of operations at non-complying properties - 14 days to fulfil DST submission requirement - Copy of letter to EUB Corporate Compliance Group (CCG) and EUB Field Office for follow-up on suspension. CCG to include non-compliance information on Corporate Performance Record and database, enforcement may be accelerated in other areas. This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.	**Day 68** – Communication with CEO of licensee/operating company, with letter confirming: - Immediate suspension of operations at non-complying properties - 14 days to fulfil gas and/or fluid analysis submission requirement - Copy of letter to EUB Corporate Compliance Group (CCG) and EUB Field Office for follow-up on suspension. CCG to include non-compliance information on Corporate Performance Record and database, enforcement may be accelerated in other areas. This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.

Calendar For Non-Compliance of Initial Pressure and Deliverability Testing, and Submission of DSTs and Gas and Fluid Analyses Requirements (continued)

LEVEL IV	**Day 69/83** - Follow-up on suspension request will begin immediately. Further Enforcement Action on the survey requirements will commence in 14 days, by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days) No activity permitted by operator at wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/submissions treated as non-routine, corporate focussed audit requirements reflective of non-routine status.	**Day 69/83** – Follow-up on suspension request will begin immediately. Further Enforcement Action on the survey requirements will commence in 14 days, by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days) No activity permitted by operator at wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/ submissions treated as non-routine, corporate focussed audit requirements reflective of non-routine status.	**Day 69/83** – Follow-up on suspension request will begin immediately. Further enforcement action on the DST submission requirement will commence in 14 days by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days). No activity is permitted by the Operator at the wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/submission treated as non-routine, corporate focussed audit requirements reflective of non-routine status.	**Day 69/83** – Follow-up on suspension request will begin immediately. Further enforcement action on the gas/fluid analysis submission requirement will commence in 14 days by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days). No activity is permitted by the Operator at the wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/submission treated as non-routine, corporate focussed audit requirements reflective of non-routine status.
LEVEL V	Inquiry into company operations, if necessary	Inquiry into company operations, if necessary	Inquiry into company operations, if necessary.	Inquiry into company operations, if necessary.

6.3 Calendar for Non-Compliance of Annual Oil and Gas Pool Pressure Survey Requirements

The following table lists the process that has been adopted by the EUB for dealing with non-compliance issues for annual testing of oil and gas pools. Each letter/communication will include a warning of the consequences at the next level, should non-compliance continue.

FAILURE TO RESPOND TO THIS LETTER WILL RESULT IN FURTHER CONSEQUENCES AND LIABILITIES TO THE LICENSEE/OPERATOR.

EUB enforcement actions will commence on or about the first business day after the timeline identified below. Enforcement may be accelerated in the case of repeat offenses.

Calendar for Non-Compliance of Annual Oil and Gas Pool Pressure Survey Requirements

LEVEL:	Responsibility of Coordinating Operator for Pool Surveys	Responsibility of Well Licensees/Operators for Cooperation and Individual Well Tests
	For all oil and gas pools requiring a pressure survey in the current year, as identified on the Annual Pool Pressure Survey Schedule, where **requirements have not been fulfilled by 31 October** (including surveys submitted that do not meet acceptable criteria):	For the Licensees/Operators of wells in the oil and gas pools requiring a pool pressure survey in the current year, that **have not cooperated** with the coordinated pool survey plan:
NOTICE LETTER	**1 November** - Letter to Coordinating Operator indicating 60 days to complete pool testing requirements. [Coordinator can submit documentation of efforts to coordinate survey, to the EUB within 14 days, to transfer responsibility and EUB enforcement actions to non-cooperative Licensee(s)/Operator(s)] See next column	**15 November** - Letter to non-cooperative well Licensee(s)/Operator(s) indicating: - 15 days to provide coordinating operator with details of plans to fulfil survey requirements, with copy to the EUB - 45 days to complete their portion of the testing requirements
LEVEL I	**1 April** - Letter to Production Manager of Coordinating Company outlining: - $1000. Fee assessed against each pool in non-compliance - 30 days to fulfil pressure survey requirements for pool - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment.	**1 April** - Letter to Production Manager of well Licensee(s)/Operator(s) outlining: - $1000 fee assessed against each non-compliant operator in pool - 30 days to fulfil survey requirements for that portion of pool - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment
LEVEL II	**1 May** – Communication with Vice President of Operations of Coordinating company with letter confirming: - 7 days to address requirements - Action plan to be submitted to the EUB - Operator/EUB meeting may be scheduled - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment. Existing approvals to increase production rates contingent upon pressure surveys to monitor	**1 May** - Communication with Vice President of Operations of the Non-Cooperating company with letter confirming: - 7 days to address requirements - Action plan to be submitted to the EUB - Operator/EUB meeting may be scheduled - Processing of applications to increase production rates for well/pool (eg. special MRL, GPP, CCP, Enhanced Recovery Recognition, penalty relief) will be deferred until pressure data from survey available for technical assessment. Existing approvals to increase production rates contingent upon pressure surveys to monitor depletion, will be reviewed and rescinded

LEVEL:	Responsibility of Coordinating Operator for Pool Surveys	Responsibility of Well Licensees/Operators for Cooperation and Individual Well Tests
	depletion, will be reviewed and rescinded where applicable unless conservation or equity factors prevail (application would be required to reinstate approval once pressure surveys accepted by the EUB). For repeat occurrences, a meeting with the VP will occur.	where applicable unless conservation or equity factors prevail (application would be required to reinstate approval once pressure surveys accepted by the EUB). For repeat occurrences, a meeting with the VP will occur.
LEVEL III	**8 May** – Communication with CEO of Coordinating company with letter confirming: - Immediate suspension of operations at non-complying properties (wells to be selected by the EUB) - 14 days to fulfil pressure survey requirements - Copy of letter to EUB Corporate Compliance Group (CCG) and Field Office for follow-up on suspension. CCG to include non-compliance information in Corporate Performance Record and database, enforcement may be accelerated in other areas. - This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.	**8 May** - Communication with CEO of Non-Cooperating company with letter confirming: - Immediate suspension of operations of non-complying properties (wells to be selected by the EUB) - 14 days to fulfil pressure survey requirements - Copy of letter to EUB CCG and Field Office for follow-up on suspension. CCG to include non-compliance information on Corporate Performance Record and database, enforcement may be accelerated in other areas. - This level may be skipped for repeat occurrences, and escalate directly to closure as detailed in Level IV.
LEVEL IV	**9 - 22 May** - Follow-up with suspension request will begin immediately. Further Enforcement Action on the survey requirements will commence in 14 days, by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days). No activity permitted by operator at wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/submissions treated as non-routine, corporate focussed audit requirements reflective of non-routine status.	**9 - 22 May** - Follow-up with suspension request will begin immediately. Further Enforcement Action on the survey requirements will commence in 14 days, by CCG: - Issuance of Formal Closure Order (which can lead to Abandonment Order in 30 days). No activity permitted by operator at wellsite without EUB permission, well(s) chained and site posted, meeting required between CCG and officers of non-complying company, corporate explanation and detailed plan filed with EUB to ensure no repeat of non-compliance, operator activities/ submissions treated as non-routine, corporate focussed audit requirements reflective of non-routine status.
LEVEL V	Inquiry into company operations, if necessary	Inquiry into company operations, if necessary

6.4 Extensions to Deadlines

If you are unable to meet the deadline indicated in the notice letter, an extension can be requested by notifying EUB Well Test staff as per Appendix C.

6.5 Licensees' Responsibilities

All licensee/operators will receive a warning letter advising that survey requirements must be fulfilled or "satisfactorily addressed" by a specified date. For annual survey requirements the notice letters go out in early November and the coordinating operator actually has until 1 April of the following year before any consequences are assessed. For initial pressures and deliverability testing, the warning letters provide 30 days to fulfil or address survey requirements.

"Satisfactorily addressed" can range from a detailed submission requesting waiver or exemption of the survey requirement (complete with substantiating information), to a telephone call requesting an extension to the deadline. To assist in determining responsibility in these cases, the EUB Well Test staff keep a complete log of all incoming calls.

The company receiving a notice letter is responsible for either fulfilling the survey requirement, addressing the requirement, or notifying the EUB that they are no longer responsible for this well. All warning letters clearly state that failure to respond within the specified timeframe will result in the assessment of a non-compliance fee of $1000.00. The assessment of this fee involves considerable administrative processes from tracking the delinquent surveys to generating the invoices and subsequent letters, and financial accounting procedures.

YOU ARE LIABLE FOR ANY NON-COMPLIANCE FEES ASSESSED IF NO EFFORT WAS MADE TO FORESTALL THE INVOICING PROCESS

6.5.1 Licensees' Responsibilities When Buying/Selling Wells

It is the responsibility of the licensees, both the seller and the buyer, to ensure a proper Transfer of Well License is filed with, and approved by, the Liability Management Section of EUB's Corporate Compliance Group. Applications for Transfer of Well License are processed within two weeks, free of charge. The process entails reviewing both companies as addressed in ID 93-2, to ensure they meet the requirements. Until an application for well license has been processed and the transfer made, the EUB considers the 'licensee of record' responsible for the well.

It is the buyer's responsibility to be aware of any survey requirements in effect for that well/pool. It is the previous licensee's responsibility to advise the EUB Well Test staff immediately of a change in Coordinating Operator of a pool, and an immediate response is expected upon receipt of any non-compliance letter to advise of a change in responsibility. A notice letter will then be sent to the new owner/licensee, and the compliance process will commence from the date of the new letter. Failure to advise the EUB Well Test staff prior to the invoicing process, will result in the previous owner being responsible for the non-compliance fee.

6.6 Inquiries and Appeals

While response to inquiries will be provided at any point in the compliance process, inquiries must be made prior to the assessment of any consequences, to avoid the $1000.00 non-compliance fee. To forestall the assessment of the non-compliance fee, "address" the issue and request an extension to the deadline if it appears the submission may be late, even if by a day or two. E-mail the well test helpline at welltest-helpline@eub.gov.ab.ca or contact the EUB Well Test staff as per Appendix C. Receipt of a request will be confirmed by e-mail. The new date will be entered into the Well Test database and the compliance process will then be administered from the revised date.

Requests received prior to the assessment of non-compliance fees or other consequences, will be processed as follows:

- The status of the well/pool in question will be changed to "UNDER REVIEW" immediately.

- The request will be reviewed and the licensee notified of the EUB's decision.

- No consequences or survey requirements will be assessed during this period.

- The EUB will only advise the licensee that the request has been denied and a survey is required for the current year if such notification occurs prior to 1 September of that year.

- Requests received after that date may result in more than one survey being required in the subsequent year, should be request be denied.

To ensure these applications are entered into the Well Test system immediately, they can be submitted via e-mail to welltest-helpline@eub.gov.ab.ca, or submitted in their own package (do not attach to any other submission), to:

Well Test Section - Systems and Resource Information
EUB
640 – 5 Avenue SW
Calgary AB T2P 3G4

When requests are received after non-compliance fees or other consequences have been assessed, the survey requirement and the non-compliance fee become separate issues. The request for change to the survey requirement will be addressed, but these requests will **not** be considered as appeals to the non-compliance fee.

To appeal a non-compliance fee, the licensee/operator must address what contact the licensee had with the EUB within the timeframe specified in the notice letter. To reduce the chance of a licensee request not getting entered into the compliance database, the EUB staff keep a complete log of all incoming calls and will verify any claim of contact.

YOU ARE LIABLE FOR ANY NON-COMPLIANCE FEES ASSESSED IF NO EFFORT WAS MADE TO FORESTALL THE INVOICING PROCESS

The EUB is responsible to get the warning letter to the correct company – to the attention of the Well Test Coordinator. (The title of "Well Test Coordinator" was selected by the Committee as the most representative or meaningful to the majority of the companies.) It is considered the licensing company's responsibility to get the letter to the appropriate person within their organization. Claiming the letter did not get to the right person is not an acceptable reason for appeal.

Grounds for appeal of non-compliance fees are:

- If the notice letter was not sent to the correct licensee.

- If the matter was addressed within the 30-day timeframe but the change was not made to EUB records.

Section 6 details situations where licensee/operators should consider requesting either relaxation or exemption from the basic requirements. This provides more flexibility for the licensee/operators to conduct the tests they need for their own use, but not at scheduled intervals tracked by the EUB. While each situation must be considered on its own merit, some general guidelines are provided to streamline the process, and to show how requests for relief may be approved. All requests should be directed to the EUB's Well Test Section of the Systems and Resource Information Group at the EUB Calgary Office.

In all cases, the need for the data should be the main reason for testing.

7 Special Testing Situations

Listed below are examples of situations where special testing may be required by the EUB. The need for special testing may be determined through the EUB's application and approval process. However, the EUB also reserves the right to require special testing, where it considers it appropriate and reasonable to do so. Special testing would usually be a temporary increase in the number of tests, and may involve specific procedures. However, in some cases, where there are environmental concerns, reduced testing and more operational restrictions may apply.

- Pool definition and development
  - reserves assignment
  - enhanced recovery evaluation
  - equity issues
  - well spacing

- Facilities approval

- Production rate controls
  - conservation concerns
  - equity issues
  - concurrent production
  - off target wells

- Anticipated enhanced recovery schemes
  - oil pools above the bubble point
  - retrograde gas pools (above the dew point)

- Operating enhanced recovery schemes
  - gas cycling
  - solvent floods
  - immiscible gas floods
  - $C0_2$ & N_2 floods
  - polymer floods
  - waterfloods

- Enhanced recovery schemes
  - representation in pattern floods
  - representation in areas of concern (pressures below/near MOP, high voidage)

- Other gas or water injection circumstances that may require more extensive testing
  - gas storage schemes
  - acid gas disposal schemes
  - water disposal

- Wellbore configurations
  - multi-lateral wells
  - dual completions

- Environmental concerns
  - safety
  - odours, noise, visual
  - flaring sour gas

- Oil sands
  - equity issues (gas/bitumen and offset oil sands lease holders)
  - mini-frac tests

- Special Requirements/Relaxation that has been granted by application:
  - Southeast Alberta Shallow Gas System
  - Provost Viking, Belly River, Basal Colorado & Mannville MU #1
  - Some shallow gas pools in North Eastern Alberta

8 Measurement

This section provides a general discussion of certain practices to be considered in the running and maintenance of pressure measurement devices.

8.1 Gauge Information

- A gauge should be chosen so that the expected value of the pressure to be measured is between 60 and 90 per cent of the gauge's rated pressure range.

- Mechanical gauges should be flexed before and after each pressure measurement to ensure the pressure recorder is functioning properly.

- Gauges should be run in tandem to track the performance of both gauges and improve the reliability of the measurements. The differences in pressure and temperature between the two gauges should always be compared.

- If a gauge shows temperature sensitivity, or if the reservoir temperature is above 95°C, an acceptable bath calibration should be available so that allowances can be made for the effects of temperature in the subsequent calculations.

- When the gauge is returned to the surface, it should be set at the depth reference elevations again, at the top of the casing flange where the wireline counter was initially zeroed. This gives a check on the accuracy of the depth measuring device. The discrepancy in counter readings at this point should not be substantially greater than indicated in the following table (in metres):

Discrepancy	0.3	0.6	1.2	2.1	4.2	7.5
Run Depth	600	1200	1800	2400	3000	3600

Where a greater discrepancy is observed, any conditions that may have caused slip and elastic deformation of the wireline should be reported.

- The maximum temperature thermometer should be read, and the maximum temperature recorded, immediately after the bomb has been retrieved from the well.

- When gauges can not be run down to the mid-point of the producing interval, the gauges should be run as low in the well as is safely possible. Under such conditions the determination of the wellbore gradient at run depth is critical to the extrapolation of run depth pressure to bottomhole pressure (at MPP). Making stops at 30 metre intervals over the last 150 metres can help to get an accurate gradient. However, be sure the gradient you use for this extrapolation makes sense (e.g. if the gauges have not encountered fluid in the wellbore of an oil well, it may not be appropriate to assume a gas gradient to MPP).

8.2 Surface Pressure Readings

The casing and tubing pressures should always be read with a deadweight tester and recorded. These deadweight testers must be calibrated to EUB standards annually, as per section 11.110 of the Oil and Gas Conservation Regulations.

8.3 Gauge Calibrations

In order to maintain accuracy and a comparative baseline in the measurement of subsurface pressures, the EUB requires that all gauges be calibrated to EUB standards. The specific requirements are set out in section 11.110 of the Oil and Gas Conservation Regulations. In short, all gauges (mechanical and electronic) require calibration within the 3 months prior to use in any pressure tests (this is generally the air calibration). In addition to the air calibrations, each gauge requires an annual bath calibration to determine temperature sensitivity. The calibrations are addressed in detail below.

Licensees/Operators are referred to the manufacturers' manuals for assistance in understanding the details of calibrations. The service companies are required to maintain adequate calibration history on each gauge, and be prepared to submit this data to the EUB upon request. However, the date of last calibration is required on every pressure test report. All deadweight testers used for calibration must have a valid annual comparison to the provincial primary standard, maintained by the EUB's St. Albert Field Centre.

8.3.1 Calibration Standards

The calibration results should be examined to determine whether the gauge is maintaining accurate behaviour, based on the following criteria:

- For mechanical gauges, the indicated pressure at 50.0-mm deflection should vary from the results of the previous calibration by not more than 0.25 per cent of the range of the gauge (theoretical accuracy limit). If it does, the deflections from individual calibration steps should be examined for consistency. If the deflections are consistent, a new trend may be assumed to have been established, and the calibration is satisfactory. If not, the calibration should be rejected and the gauge re-calibrated.

- The criterion for adequate temperature compensation is based on a comparison between hot-liquid-bath and air calibrations. The difference should not exceed 0.25 per cent of the gauge's range. Whether or not it does so may be determined by substituting the deflections from the bath calibration into the equation obtained from the air calibration, then calculating the difference between the resulting bath calibration pressure and the air calibration pressure. If the difference is greater than the gauge's theoretical accuracy, the instrument may be considered temperature-sensitive at that pressure. In this way, it may be determined whether the gauge is influenced by the calibration temperature, and through what

pressure range temperature sensitivity is occurring. The gauge owner is then expected to use the bath calibration to calculate the results of pressure surveys when conditions are similar to those in the bath calibration.

- Electronic gauges require the same frequency and accuracy of calibration as that specified for mechanical gauges.

8.3.2 Calibration of Permanent Gauges

In instances where a permanent gauge is installed downhole, the three-month calibration requirement defeats the purpose of a permanent gauge. These gauges can provide good data. However, problems are often experienced over time if a maintenance program is not followed, with periodic checks to ensure the ongoing accuracy of the gauge. When a procedure is planned that requires pulling a permanent gauge, the opportunity must be used to calibrate the gauge. Further information on maintenance of these gauges can be obtained from their respective manufacturers.

8.3.3 Special Calibration Notes

The following comments are offered as further clarification of EUB's policy with regard to pressure-gauge calibration:

- It is desirable to calibrate a gauge in, as nearly as possible, the same conditions as prevail in the field.

- At least two sets of readings should be obtained for each calibration. If consistency between the two is not evident, the gauge should be closely examined for damage.

- Sets of calibration steps should be spread out across the chart so that any damage to the chart carrier will become apparent.

Appendix A Reference Material

1. Oil and Gas Conservation Regulations.

2. Alberta Occupational Health and Safety Division, Well Testing - Minimum Guidelines for Safety Enhanced Field Operations, 1988.

3. ERCB IL 87-9, Revised Procedures for Oil Production Allowable Controls and New Oil Well Production Period, August 1987.

4. ERCB Guide 3, Gas Well Testing – Theory and Practice, Fourth Edition, September 1979.

5. ERCB Report ST __-18, Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids, and Sulphur.

6. ERCB Report ST __-35, Alberta Reserves of Gas, Complete Listing.

7. ERCB ID 97-02, Sour Well Licensing and Drilling Requirements, June 1997.

8. ERCB Guide 5, Calculating Subsurface Pressure Via Fluid-Level Records, Second Edition, December 1978.

9. 19__ Provincial Program of Subsurface Pressure Surveys for Conventional Crude Oil Pools.

10. 19__ Provincial Program of Subsurface Pressure Surveys for Gas Pools.

11. EUB Guide 52, Electronic Capture of Well Test Data, January 1999.

12. EUB IL 91-2, Sour Gas Flaring Requirements and Changes to Regulations, March 1991.

13. EUB ID 99-__and Guide __, Upstream Petroleum Industry Flaring Requirements (pending).

14. EUB ID 98-4, Electronic Capture of Well Test Data, December 1998.

15. ERCB IL 83-1, Reservoir Limits Tests on Discovery Oil Wells: A Guide, January 1983.

16. EUB Guide 7, Production Accounting Handbook.

17. The Petroleum Society Monograph Number 1, Determination of Oil and Gas Reserves.

18. EUB Guide 56, Energy Development Application Guide and Schedules, April 1997.

19. EUB ID 94-04, Noise Control Directive, August 1994.

20. Recommended Practices for Flaring of Associated and Solution Gas at Oil Production Facilities (CAPP).

21. Alberta Ambient Air Quality Guidelines.

22. GPSA Engineering Data Book (Eleventh Edition).

23. Forest and Prairie Protection Regulations (AR 135/72).

24. Alberta Environmental Protection and Enhancement Act – Draft Air Quality Model Guidelines.

25. EUB IL 97-04, Emissions from Glycol Dehydrators, November 1997.

26. EUB ID 93-02, Requirements for the Issuance of a Well Licence or Approval of Well Licence Transfers, July 1993) (AMENDED BY ID 97-04).

Appendix B Regulations Pertinent to Well Testing

7.055 (1) Where gas

(a) from a well producing gas containing more than 50 moles per kilomole of hydrogen sulphide, or

(b) produced from a well designated as a critical sour well

is flared during any test, during any period of cleaning out of the well or during well servicing operations, the licensee shall obtain written approval of the Board of the method, stack height and equipment to be used to flare the gas.

(2) An application submitted under subsection (1) shall be in accordance with section 15.240.

7.060 (1) This section applies to any well which produces gas containing more than 10 moles per kilomole of hydrogen sulphide, or such higher or lower ratio as the Board may be order stipulate with respect to any well, pool or area, having regard to pressures, nature of production, remoteness of the area and other circumstances.

(1.5) Where no gas analysis has been taken from the well within the preceding 12-month period, gas from the formation produced at the well shall be tested at the commencement of flaring to determine the hydrogen sulphide content.

(2) Where a flare line is installed at a gas well for burning gas produced during normal depressurizing operations or other routine flaring, the licensee shall provide a flare stack constructed in accordance with the specifications for a flare line set out in subsection (4).

(3) Where a pressure relief valve, rupture disk or burst plate is installed on a separator, dehydrator or other pressure vessel which receives production from a gas well, the valve, rupture disk or burst plate fitting shall be connected to the flare stack required by subsection (2).

(3.1) Where a pressure relief valve, rupture disk or burst plate is installed on a separator, treater or other pressure vessel that receives production from an oil well, the vessel shall be equipped with pressure and liquid level sensors that cause a valve installed on the inlet to close and isolate the vessel from the flow stream.

(3.2) The Board may, on application exempt an operator from the requirements of subsection (3.1) and permit the use of a tank referred to in section 8.031 where, in the opinion of the Board, the nature of the production, the remoteness of the area or any other circumstance warrants the exemption.

(4) Where gas is produced from any well to the atmosphere for a period exceeding 10 minutes during a drill stem test, the licensee shall burn the gas through a flare line which shall

(a) terminate with a vertical riser of at least 12 metres or such greater or lesser height has the Board directs in a particular case,

(b) be provided with a suitable guard to prevent the wind from extinguishing the flame,

(c) if the gas flow may be intermittent, be provided with a pilot or ignition device to ensure continuous ignition of any vented gas, and

(d) be provided with a suitable vessel to separate and collect any liquids to prevent the liquids from reaching the flame.

(5) Repealed.

(6) Repealed.

(7) Where liquids are produced from a well during any test, during any period of cleaning out the well or during well servicing operations, the liquids shall be separated and piped to a storage tank and all gas shall be discharged to an approved flare stack.

(8) Unless the licensee of a well equips and operates the well so that the maximum operating flow line pressure cannot exceed 200 pounds per square inch gauge, he shall install on the wellhead a valve which closes automatically in the event of an uncontrolled flow of oil or gas.

(9) The licensee of the well shall, when requested to do so by the Board, file with the Board an outline of emergency procedures to ensure public safety that will be followed by the licensee in the vent of an uncontrolled emission of oil or gas.

(9.5) At least 24 hours in advance of any flaring operations, notice shall be given

(a) to the Board field office,

(b) for oil wells, to all rural residents and administrators of any incorporated centres or hamlets within a 1.5-kilometre radius of the well, and

(c) for gas wells, to all rural residents and administrators of any incorporated centres or hamlets within a 3-kilometre radius of the well.

(10) Board may by order and upon application exempt a well, pool or field from any provision of this section where, in the opinion of the Board, the pressure, nature of production, remoteness of area or other circumstances warrant the exemption.

11.060 The Board may require the licensee of a well to conduct or run any reasonable or conventional test, analysis, survey or log or perform any instrument calibration, and to submit to the Board the information so obtained.

11.070 (1) Where recoveries on a drill stem or wireline test from a well which when drilled is not within a designated pool permit good sampling, the licensee shall submit to the Board analyses of representative samples of the oil, gas and formation water recovered from each formation, on approved forms, and report at least the following information:

OIL
Density in kilograms per cubic metre at 15° C of the water free and sediment free oil
Sulphur content of the water free and sediment free oil, weight per cent
Saybolt Universal Viscosity of the water free and sediment free oil at 21°C, seconds

GAS
Gross Heating Value, moisture and acid gas free, measured or calculated from an analysis
Hydrogen sulphide, moles per mole
Carbon dioxide, moles per mole
Density in kilograms per cubic metre, measured or calculated from an analysis

WATER
Chloride content, grams per cubic metre
Resistivity, ohm metres at 25°C
Total solids content on ignition, grams per cubic metre pH

(2) Following the first production or deliverability test of a well which when completed is not within a designated pool, the licensee shall submit to the Board analyses of representative samples of the produced oil, gas, condensate, formation water and of gas and condensate combined, on approved forms, and report at least the following information:

OIL

Sulphur content of the water free and sediment free oil, weight per cent
Saybolt Universal Viscosity of the water free and sediment free oil at 21°C and 38°C, density in kilograms per cubic metre at 15°C of the water free and sediment free oil

GAS

Composition in moles per mole of methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes, heptanes plus, nitrogen, helium, carbon dioxide, and hydrogen sulphide. The composition in moles per mole converted to litres per thousand cubic metres at 101.325 kPa and 15°C, of propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes, and heptanes plus
Gross Heating Value, moisture and acid gas free at 101.325 kPa and 15°C, measured or calculated from the analysis
Density in kilograms per cubic metre, measured or calculated from the analysis
Pseudocritical pressure and temperature calculated from the analysis

CONDENSATE

Mole fractions and liquid composition in moles per mole of nitrogen, carbon dioxide, hydrogen sulphide, methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes, and heptanes plus
Density in grams per cubic centimetre at 15°C, density in kilograms per cubic metre at 15°C, and molecular weight in grams per mole of the heptanes plus fraction
density in kilograms per cubic metre at 15°C of the water free and sediment free condensate

WATER

Solids content in kilograms per cubic metre and the calculated per cent solids of chloride, bromide, iodide, carbonate, bicarbonate, hydroxide, sulphate, calcium, magnesium, sodium, and total solids
Total solids content by evaporation at 110°C, 180°C, and at ignition
Density in kilograms per cubic metre at 15°C
pH
Hydrogen sulphide, grams per cubic metre
Refractive index at 25°C
Resistivity, ohm metres at 25°C

GAS AND CONDENSATE COMBINED

Mole fractions and gas composition in moles per mole of nitrogen, helium, carbon dioxide, hydrogen sulphide, methane, ethane, propane, iso-butane, normal butane, iso-pentane, normal pentane, hexanes, and heptanes plus

Molecular weight in grams per cubic metre, measured or calculated from the recombined analysis

Pseudocritical pressure and temperature calculated from the recombined analysis

Molecular weight and specific gravity of liquid hydrocarbons

Liquid to gas ratio expressed in cubic metres per cubic metre

(3) The analyses of gas and condensate combined, pursuant to subsection (2), may be obtained from either an analysis of a representative combined well stream sample or from a calculated recombination of the analyses of separate gas and condensate samples.

(4) The analyses required pursuant to subsections (1) and (2), shall, within 45 days of the completion of the test, be submitted to the Calgary office of the Board, accompanied by the following details of the taking of the samples:

(a) in the case of a drill stem test,

(i) well name and unique identifier of the well,

(ii) point of sampling,

(iii) pressure and temperature at point of sampling,

(iv) amount of water cushion,

(v) mud type (lime, gypsum base, salt or the like),

(vi) test recovery,

(vii) internal tested, and

(viii) formation tested,

or

(b) in the case of a production or deliverability test,

(i) well name and unique identifier or the well,

(ii) point of sampling, and

(iii) pressure and temperature at point of sampling.

(5) The Board, upon application, may grant relief from the provisions of this section where it is satisfied that the formation tested in an extension of a pool previously designated and adequately sampled.

11.100 The licensee shall supply to the Board within 1 month of the finished drilling date of a well a clear and non-fading print of a pressure chart and report containing complete details on fluid recoveries and other pertinent particulars for each drill stem test or wire line test taken at the well.

11.101 Where a well is drilled with air as the drilling fluid, the licensee shall supply to the Board, within 1 month of the finished drilling date of the well, a report containing complete details concerning each test made to determine the rate at which gas flowed from the well.

11.102 (1) The licensee of a well or the representative of the licensee shall conduct and report to the Board tests for all gas and oil wells in accordance with the current edition of Guide 40, "Pressure and Deliverability Testing Oil and Gas Wells – Minimum Requirements and Recommended Practices", published by the Board.

(2) Notwithstanding subsection (1), the Board may, upon application by the licensee of a well or the representative of the licensee, grant relief from any or all of the requirements in the Guide.

11.103 Repealed.

11.110 The operator of a well shall use instruments that meet the following requirements:

(1) any dead weight gauge that is used to calibrate wire line instruments for taking subsurface pressure measurements shall be compared annually with the Board's primary dead weight gauge;

(2) the calibration shall be obtained using an approved dead weight gauge at a minimum frequency

(i) within 3 months prior to use in any survey,

(ii) twice after repairs or abnormal stresses, and

(iii) once annually under the necessary conditions to check temperature sensitivity.

11.120 (1) The licensee of a well shall supply to the Board without delay the data and results of:

(a) each bottomhole sample analysis or other pressure-volume-temperature analysis, in duplicate

(b) each measurement or test made on the well for the purpose of obtaining information pertaining to a formation in which the well is completed, including volumes of oil, gas, condensate or water produced, flowing or static pressure measurements, pressure build-up, fall-off and drawdown tests, reservoir limits tests, interference tests, and two-rate tests,

(c) where the well is primarily productive of gas, one copy of each deliverability test including field notes, flow rate calculations, summary sheet (Form EG-32) and any supplementary data and calculations related to a proper interpretation of the test, and *(this regulation is currently being updated)*

(d) each measurement of the reservoir gas-oil, oil-water, or gas-water interface.

(2) The licensee of a well shall supply to the Board, within 6 months of the date of any relevant laboratory analysis, two copies of a report of any laboratory study assessing miscible displacement of reservoir oil or gas.

11.130 Repealed.

11.135 (1) Where a gas well is being cleaned up or tested, the amount of gas flared shall not exceed 600 thousand cubic metres including that produced during the initial clean-up period, unless the prior approval of the Board therefor has been obtained.

(2) Where a gas well is being cleaned up or tested, the flaring shall be minimized and be subject to section 7.060 of these Regulations.

(3) The licensee of the well to be cleaned up or tested in accordance with this section shall notify the Board, through its appropriate area office, of the intention to perform such operations not less than 3 days prior to commencement of the operations.

15.240 An application under section 7.055 for approval of the method, stack height and equipment used to flare gas containing more than 50 moles per kilomole hydrogen sulphide shall include

(a) the height and diameter of the proposed stack,

(b) a map showing the location of the well, limits of any incorporated centres, hamlets, rural residences and recreation areas within a 3-kilometre radius of the well site, and a 1:50,000 scale topographic map showing a minimum radius of 7 kilometres from the well site,

(c) if the area within a distance of 100 times the stack height is more than 50 per cent treed, the average tree height and the distance from the nearest trees to the base of the stack,

(d) the maximum, minimum and average rates at which the well will be flowed,

(e) the total volume of gas to be flared,

(f) a description of the type of operations to be performed that will require the flaring, detailing any well test design parameters, and justification for the flare rates and volumes requested,

(g) the most recent analysis on a condensate-free basis of gas from the well in question or, if a gas sample from the well is not available, an analysis of gas from the same pool,

(h) the anticipated rate of liquid production,

(i) the method of handling and transporting the liquid production from the well,

(j) the name and location of the facility to which the liquids from the well will be transported, and

(k) a statement as to whether the well has been designated as a critical or non-critical sour well.

Other requirements are detailed in ID 91-2 and will be updated in the *"Upstream Petroleum Industry Flaring Guide"*.

EXCERPT FROM APPENDIX 4 - EUB GUIDE 7 – PRODUCTION ACCOUNTING HANDBOOK

"You must file an S-1 statement for a well that has produced any fluid (crude oil, crude bitumen, condensate gas, or water) for any reason, reporting the volumes produced, regardless of the requirement for filing an S-4 statement." When an S-1 statement is filed, regardless of whether the well produced, an S-2 statement must also be filed.

Appendix C Well Test Contact List

EUB Website URL's:

EUB Home Page:
www.eub.gov.ab.ca

Well Test Electronic Data Capture:
www.eub.gov.ab.ca/bbs/dds/welltest/welltest.htm

Annual Subsurface Pressure Survey Schedules and Outstanding Initial Pressure, Deliverability, DST, Gas and Fluid Analysis Listings:
www.eub.gov.ab.ca/bbs/data/welltestreq.htm

Alberta Environment Protection – Fire Control Orders:
www.gov.ab.ca/env/forests/fpd/fco2.html

EMAIL ID's

All well testing enquiries (other than electronic data submission):
Welltest-helpline@eub.gov.ab.ca

Electronic data submission problems, questions and concerns:
ecommerce-help@mail-ecx1.eub.gov.ab.ca

PHONE NUMBERS

Welltest compliance warning notices and issues:
(403) 297-6925, 297-8408, or 297-4424

Enquiries regarding the annual subsurface pressure survey schedules:
(403) 297-8408 and 297-8499

Well Test Flaring (gas volumes > 600 e^3m^3 containing H_2S < 50 moles per kilomole)
(403) 297-4424 or 297-8570

Well Test Flaring (containing H_2S > 50 moles per kilomole)
(403) 297-6977

Electronic data submission problems, questions and concerns:
(403) 297-8408 or 297-6179

Information Services Enquiries (data dissemination and sales):
(403) 297-8190

ATTACHMENT I

SAMPLE LETTER FOR COORDINATING OPERATORS

(as per section 4.5.5 of this Guide)

(Date)

(Company Name and Address)

OR

To All Operators of the _____ Pool

Dear Sirs:

199? SUBSURFACE PRESSURE SURVEY REQUIREMENTS
_____ POOL

The Alberta Energy and Utilities Board (EUB) has designated _____ (*company name*) the responsibility of coordinating pressure survey requirements for the above pool, as listed in the current annual survey schedule. In accordance with EUB Guide 40, Pressure and Deliverability Testing Oil and Gas Wells, _____ (*number*) well(s) must be surveyed this year.

To determine the best plan for this pool, considering survey quality, areal coverage, and cost we are requesting all pool operators to review their operations and submit possible candidates, acceptable methods and timing for surveying. We hope that this will enable us to gather quality data for reservoir evaluation and management at a reasonable cost while minimizing production losses.

Please contact the undersigned at _____ by (*date)* with your information.

Yours truly,

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